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THE FIRST INTERNATIONAL SYMPOSIUM ON

OIL AND GAS EXPLORATION AND PRODUCTION WASTE MANAGEMENT PRACTICES

SEPTEMBER 10 - 13, 1990
NEW ORLEANS, LOUISIANA

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THE ALBERTA DRILLING WASTE REVIEW COMMITTEE - A COOPERATIVE APPROACH TO DEVELOPMENT OF ENVIRONMENTAL REGULATIONS

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Introduction

The Province of Alberta contains the bulk of the producing oil and gas resources of Canada. The oil industry is a major factor in the economy of the Province and a significant contributor to the national economy. An average of approximately 6000 wells per year have been drilled over the past ten years. The wells have been drilled in a wide variety of geological formations at depths ranging from 500-5000 m (1,650-16,500 feet). Over the past decade drilling technology has become more sophisticated and the drilling muds and mud additives used for drilling have become more diverse and complex. The end result is that the wastes created by drilling have also become more diverse and complex.

In Alberta, the Energy Resources Conservation Board (ERCB) has the responsibility for managing the Province's energy resources and regulating the energy industry. This includes the establishment of policies, regulations and guidelines respecting the handling and disposal of energy industry wastes, although various other government agencies also have some regulatory responsibility regarding waste transportation and disposal. The disposal of drilling wastes in Alberta is currently regulated by an "interim" guideline developed in 1975.

Existing Sump Regulations Inadequate

During the 1980s, as environmental concerns rose to the top of the public and political agenda, governments everywhere have been scrambling to develop and/or update environmental regulations to cope with public demands and to incorporate constantly expanding knowledge of environmental problems and the technology available to deal with those problems. Industry, in turn, is

scrambling to keep up with the regulatory tide and to deal effectively with environmental issues, including management of wastes.

In Alberta in 1987 there was a climate of dissatisfaction and criticism by all parties (government, industry and public) when it came to the handling and disposal of drilling sump wastes. A round-table meeting was organized by the ERCB and the Canadian Petroleum Association (CPA) to enable all participants to discuss their concerns, complaints and frustrations. Representatives of numerous government agencies and oil industry organizations were present. The group quickly developed a list of issues and concerns. The discussion which followed made it clear that the root cause of many of the problems was that the 1975 guidelines were inadequate to deal with contemporary drilling technology and environmental concerns. Different government agencies were developing separate ad hoc approaches that sometimes conflicted, with industry caught in the middle. Disposal techniques favoured by some companies and regulators were unpopular with other companies and regulators. There was substantial uncertainty and confusion.

It was apparent that what was required were new regulations that would reflect current drilling technology, waste treatment technology and environmental concerns.

There had been a history in Alberta of forming joint government-industry committees to investigate areas of common concern and to make recommendations on government policy and regulation. In fact, the 1975 sump disposal guidelines had been developed in this way. In August of 1987, senior representatives of industry and government approved the establishment of the Drilling Waste Review Committee (DWRC). The task of the Committee was to prepare a new comprehensive guideline for the management of drilling sump wastes for Alberta. The new guidelines would also provide the basis for new regulations. The Committee would be co-chaired by representatives of the ERCB and the CPA (the authors of this paper). There were also representatives of Alberta Environment, Alberta Department of Forestry, Lands and Wildlife and the Independent Petroleum Association of Canada (IPAC).

Cooperative Process Taken

Within a short period of time the Committee had agreed to the process which it would use to develop the new sump disposal guidelines. The objective and contents of the guidelines were agreed upon and twelve technical sub-committees (one per guideline chapter) were created. Each sub-committee was chaired by a DWRC member. Each sub-committee chairman was responsible for filling his sub-committee with experienced individuals from industry and government.

Each sub-committee report (section of the guideline) was to be a consensus report of the technical sub-committee. Cross sub-committee appointments and the circulation of draft reports would help keep the effort coordinated. The DWRC would be responsible for integrating the sub-committee reports and for conducting a broader review (including the public) of a draft guideline before submitting a final draft to the ERCB for implementation.

Progress is slow, but commitment remains

The twelve sub-committees were quickly formed and draft reports began to appear by late 1987. It quickly became obvious, however, that there were two key areas that would take longer to resolve. One was the characterization of the wastes: which characteristics should be measured and how should it be done. The characterization of sump wastes should be comprehensive enough to detect levels of contaminants that would be of concern, yet the procedure should also minimize the time and expense required. The process should be effective and efficient.

The second, and perhaps most difficult, area is reaching agreement on criteria: what levels of contaminants are safe for disposal. This debate continues across our society for a multitude of wastes - liquid, solid and gaseous. What levels of contamination will or might create an undesirable environmental or health effect? Drilling sumps contain waste drilling fluids, drilling muds and the rock cuttings from the drilling operation. If they are allowed to settle or are treated, there are liquid and solid (sludge and cuttings) phases to dispose of. Some drilling muds are very salty. Some have a high oil content. Some may contain heavy metals. Wastes containing high salt, oil and/or heavy metal concentrations are a concern because improper disposal can result in undesirable impacts to ground and surface waters, vegetation, wildlife, domestic animals and perhaps humans.

Considerable debate within and between the Characterization and Criteria sub-committees led to a decision to commission an independent review of disposal criteria for drilling wastes in other jurisdictions, a review of the concentration of the various waste constituents that could impact vegetation and a recommendation as to what soil loading rates would be safe. This study took approximately six months to complete.

The criteria suggested by the independent report were considered by all parties to be safe, in that the concentrations would not affect plants or animals if sprayed onto or worked into the topsoil. However, industry representatives generally felt that the proposed criteria were unnecessarily strict and that the broad suite of analytical procedures would be costly and time-consuming to conduct.

The debate of these issues led to the realization to nobody knew what the impact of adopting the proposed criteria would be. There was no suitable database of sump chemical analyses to compare to the proposed criteria. Would 10% of the sumps fail the criteria or would 10% pass? It was agreed that a sump characterization study was required to document the physical and chemical nature of drilling sump wastes in Alberta. This study is currently underway. A final report is expected early in 1991.

End product will be effective and efficient

The cooperative approach to development of environmental regulations has several distinct advantages over alternate methods.

- Industry obtains a better understanding of the political driving forces which are compelling environmental agencies to develop new environmental regulations.

- Government agencies gain a better understanding of the economic implications of potential regulatory alternatives before new regulations are implemented.

- Government agencies obtain a better understanding of the problems or even the feasibility of compliance with potential regulatory standards.

- More experience and knowledge is available to evaluate regulatory alternatives and find workable and effective solutions.

- Any policies, regulations or guidelines that result will have widespread credibility and acceptance leading to quicker implementation and fewer legal challenges.

The end of the story

Unlike Paul Harvey, we do not yet have the end of this story. The sump characterization study will provide very valuable data by late this year that will assist us in moving quickly to wrap up this project. It has taken longer than originally expected, but all parties remain committed and convinced that the process will result in drilling waste regulations that will protect the environment and incorporate analytical and disposal procedures that are effective and efficient.

The cooperative approach to developing environmental regulations being utilized in this situation may not be appropriate for all new environmental regulations, but it clearly reflects and supports the trend throughout North America to a consultative approach to the resolution of environmental issues.

DRILLING WASTES PAPER - SLIDES*

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18	Photo of smiling, contented bureaucrat
19	Photo of smiling, contented drilling foreman
20	Photo of smiling, contented cow

* Not necessarily in order.

SUBCOMMITTEE CHAIRMEN AND MEMBERSHIP

1. TERMS (CPA - MEAD)
   Loose (FLW)

2. SOURCES (CPA - STUART)

3. RESPONSIBILITIES (ERCB - LILLO)
   Wolff (Suncor), Creasey (ERCB), Fernandez (AE), Lloyd (FLW)

4. PREPLANNING (FLW - LLOYD)
   Sitar (Mobil), Onciul (AE), Hartley (FLW), Creasey (ERCB),
   Wolff (Suncor), Rattliff (AFS)

5. DESIGN (CPA - STUART)
   Cartwright (Shell), Karasek (FLW), Hughes (Mobil), King (AFS)

6. CONTROL (IPAC - LIKELY)
   Molnar (Amoco), Anderson (Shell), Stychyshyn (North Canadian Oil)

7. CHARACTERIZATION (AE - FUJIKAWA)
   O'Leary (Shell), Moynihan (Esso), Roberts (ERCB), Abboud (ARC),
   Macyk (ARC), Korchinski (ERCB)

8. CRITERIA (ERCB - LILLO)
   Lesky (Husky), Birchard (Esso), Takyi (FLW), Korchinski (ERCB),
   Roos (Amoco), Ferderko (Gulf)

9. TREATMENT (CPA - MEAD)
   MacDonald (Esso), Van de Pypekamp (Shell), Cole (FLW),
   Johnson (AEC), Wilson (AEC), Waisman (ERCB), Krassman (AFS)

10. CLOSURE (FLW - LLOYD)
    Silkie (Esso), Scott (Shell), Pryce (BP), Kremeniuk (FLW),
    Schneidmiller (AFS)

11. MONITORING (FLW - LLOYD)
    McCoy (Canterra), Kohlman (PC), Ceroici (AE), McFadden (AFS)

12. RECORDS (CPA - STUART)

ALBERTA'S OIL AND GAS RECLAMATION RESEARCH PROGRAM

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Abstract

There are over 130,000 wellsites and 200,000 km of pipelines in Alberta, which have disturbed an estimated 2331 square kilometres of land. The Alberta government, through the Reclamation Research Technical Advisory Committee (RRTAC), has developed a research program to identify suitable methods of reclaiming these disturbances. RRTAC is working together with industry (the Canadian Petroleum Association and the Independent Petroleum Association of Canada) to develop environmentally-safe methods for disposal of drilling wastes, and to determine suitable ways to return land to a condition capable of sustaining an approved land use. Funding for the research comes from the Alberta Heritage Savings Trust Fund.

This paper will discuss the nature and effectiveness of the joint government/ industry research approach and will highlight some of the projects undertaken.

Drilling waste research has focused on: waste characterization, effects of various waste rates and types on plant growth, sump siting criteria, evaluation of burial as a disposal option, and developing a manual to help select surface disposal options.

Activated charcoal has been evaluated for effectiveness in inactivating soil sterilants.

Soil compaction work has looked at identifying how to measure compaction, determining if compaction problems exist on oil and gas wellsites, and relating compaction to plant growth.

Introduction

Exploration, development, transport and processing of oil and gas is one of Alberta's largest industries. There are over 130,000 wellsites and 200,000 km of pipelines in Alberta, which have disturbed an estimated 2331 square kilometres of land (1). Provincial regulations (2) require that all industrial developments in the province which disturb the land surface meet established soil conservation and reclamation criteria. Larger surface disturbances, including oil sands developments within a well defined region (3) and pipelines greater than 15 cm

in diameter and 16 kilometres in length (4), require more extensive planning and prior approval by provincial regulatory authorities.

The Alberta Land Conservation and Reclamation Council is responsible for approving the development and reclamation plans for all regulated disturbances and for the certification of all reclaimed disturbed sites. The Council established the Reclamation Research Technical Advisory Committee (RRTAC) to provide relevant technical information necessary to carry out Council functions. RRTAC's role is two-fold: first, to coordinate provincial government reclamation research, and to act as a clearinghouse for information on other reclamation research activities in industry and educational institutions; and, second, to fund and manage a research program to provide information on a variety of reclamation topics of interest to both government and industry. RRTAC and the Council have set up five research program areas, one of which deals with oil and gas issues.

The Oil and Gas Reclamation Research Program (OGRRP) is a joint effort between the provincial government and Alberta's oil and gas industry whose focus is on reclamation of all types of oil and gas facilities, including wellsites, on- and off-site drilling waste sumps, access roads, compressor stations and batteries, and pipelines. Specific program objectives include: developing environmentally-safe methods for disposal of drilling wastes (fluids and solids); and, evaluating methods for returning land to a condition capable of sustaining an approved land use.

The program is managed by a committee of reclamation specialists from several provincial government departments and representatives of industry from the Canadian Petroleum Association and the Independent Petroleum Association of Canada. These specialists work together to prioritize research needs, develop research projects to address these priorities, select contractors to undertake the work, and evaluate progress and the final reports from the studies. Results from all studies are made available to government, industry and the public to ensure that all interested parties have access to the most current information when making development and reclamation decisions.

We have concentrated on three issues to date: drilling waste disposal; soil sterilants; and, compaction. Soil handling practices for pipeline construction are also starting to be investigated. The remainder of this paper will discuss the nature of these problems in Alberta and how the research program is attempting to address them.

Drilling Wastes

In 1984, RRTAC sponsored a two-day workshop on drilling waste disposal in Alberta (5). The workshop was designed to promote a better understanding between government regulators and industry about:

(a) the mud components used, their purposes and need;
(b) constraints on industry with drilling and industry clean-up practices;

(c) environmental considerations such as soil, vegetation, groundwater and surface waters when disposing of wastes;
(d) government regulations, procedures and concerns; and,
(e) potentially toxic constituents within drilling wastes.

Our Oil and Gas research program has grown out of these initial discussions.

Siting

The physical location of drilling waste disposal pits must be carefully chosen to minimize the potential for subsurface spread of leachates that may be generated from the wastes (6). Knowledge of site characteristics such as: the distance between the disposal site and the nearest surface water body or groundwater supply; the depth to the watertable; the watertable gradient away from the site; and, the type and thickness of geologic material through which the contaminated water could migrate, is required to make decisions on the suitability of a waste pit location. Knowledge of proposed waste pit contents and their likely effects on the permeability of pit liners is also important.

RRTAC funded a project to evaluate the potential for developing an expert system that would allow these decision making steps to be computerized. The consultant reported that such a system could be produced, but that a considerable data base would need to be developed to allow for the system to be effective (7).

In addition to the computer study, a literature review was conducted to assess the effectiveness of geological containment of drilling wastes in sumps (8). Knowledge of material permeability makes for more informed sump siting decisions.

Characterization

Three basic drilling muds and variations thereof are used for oil and gas exploration in Alberta (9). The freshwater gel bentonite is most commonly used, followed by the salt water systems which use sodium or potassium chlorides. The oil invert drilling mud is also used, particularly in the mountainous areas of the province, and is gaining in popularity with some companies. Diammonium phosphate (DAP) mud is also being used.

The wastes produced from drilling operations contain many complex organic and inorganic compounds that are added at various stages of the drilling process (10). The materials that start out as drilling mud are usually extensively altered chemically and physically by the time they enter a waste pit. The muds can be altered by heat and pressure effects associated with drilling and by the addition of drill cuttings brought up with the mud system. The materials found in the waste pit can also be changed chemically and physically by other products that are purposely or inadvertently added to the pit. Caustic soda, rig wash, diesel fuel, waste oil from machinery, metal and plastic containers, and other refuse often find their way into a waste pit (11).

A thorough physical and chemical analysis of the liquid and solid phases of wastes generated by drilling operations utilizing the different mud types is one of the prerequisites to assessing the potential environmental hazard of the

disposal of these wastes. RRTAC funded an initial project to provide a scientific basis for development of guidelines for drilling mud solids disposal that optimizes environmental safety and cost effectiveness. Drilling waste fluids and solids were collected from sumps at wellsites in three regions of the province. Samples were collected at several depths in each of several locations within a sump to determine spatial variability in the waste properties. A suite of chemical analyses was performed to characterize both solids and fluids. The sump solids were mixed at various rates with a soil indigenous to the respective region and planted to a grass species typically used in reclamation. The results of these greenhouse trials provided preliminary indications of how much of each waste type can be added to soil without seriously degrading soil capability (12).

Following up on this research, and recognizing that only a limited number of sumps were sampled, a broader sampling of sumps is currently underway. This new study will provide data to a joint government and industry task force that is currently updating the existing guidelines/criteria for disposal of drilling wastes in Alberta. RRTAC funded the first portion of this work which was a detailed sampling and analysis protocol for use in the field study (13). Industry is now funding the collection and analysis of wastes from up to 100 sumps through a special levy on well site owners. Finally, RRTAC will pay for the data synthesis and interpretation, and production of a final report.

Disposal

Drilling wastes are currently disposed of in Alberta by burying, trenching, squeezing, or spreading. Each of these disposal methods impacts the environment in different ways. For example, interactions of waste constituents with groundwater is much more likely to occur if wastes are trenched or buried as opposed to surface spread. The reverse is true for surface soils and plants. When considering these various waste disposal options, both industry and government staff have the following objectives in mind (14):

(a) to minimize deteriorization of groundwater and surface water quality;
(b) to control the changes in soil and site characteristics so that productive use of the site may occur after waste disposal ceases; and,
(c) to minimize closure requirements and post-closure care.

Our first research in this area focused on trying to develop a manual that could be used by field staff to determine whether a waste could be safely spread on a given soil surface (15). The manual was prepared with the assistance of field staff, however after testing the system in the field it became apparent that changes were required. A follow-up study was designed to revise and update the manual (16), specifically by:

(a) developing a more definitive drilling waste disposal decision flow chart;
(b) developing a glossary or simplifying terminology used in the manual;
(c) indicating what parameters could be tested in the field, why they should be tested, and the appropriate procedures to be used;
(d) redefining the calculations to determine sump contents;

(e) providing critical levels for parameters so that calculations are completed;
(f) condensing and clarifying the checklist for fieldmen;
(g) expanding on the guidelines for obtaining representative samples; and
(h) developing a computer program that will allow users to do the calculations prescribed in the manual.

The revised manual is expected to be released early in 1991.

There has been a movement, within some sectors of the government, away from burying in sumps as a disposal option because of concerns about potential for migration of contaminants into groundwater. Therefore, a project was initiated to review the international literature to determine the environmental acceptability of burial of drilling waste solids. One of the most difficult tasks in this study was to come to some agreement regarding the terms to be used when describing the various methods of burial (e.g., burial, containment, trapping, landfilling, etc.). The project was completed and a final report will be available late in 1990.

Diesel fuel forms the liquid portion of invert drilling muds rather than water. Therefore, the organics in the waste may be bio-degradable in the soil, and landfarming of this type of drilling waste may be an environmentally sensible option. A multi-year study will: characterize an invert waste, determine degradation rates in controlled laboratory and greenhouse conditions, and determine suitable waste application rates for field disposal through a field study. Petro-Canada has supplied the invert waste and a field location for the research.

Residual Herbicides

Soil sterilants, residual herbicides that render the treated soil unfit for plant growth for relatively long periods of time, have been used in Alberta on wellsites, rights-of-way and other industrial areas for total vegetation control. Such vegetation control measures reduce fire hazards and improve aesthetic appearance. The treated areas can remain devoid of vegetation for many years depending upon the type and rate of soil sterilant used, and the soil and climatic conditions. Furthermore, in the past it was not uncommon to use more than the recommended rates of these chemicals for achieving long-term vegetation control with a single application. Bromacil and tebuthiuron are the commonly used soil sterilants in Alberta.

Once a sterilant-treated site is abandoned, it may take several years before the site is restored to its original capability. The site also becomes a potential source of contamination through surface runoff and wind dispersion of soil sterilants onto adjoining untreated land. In Alberta, the extent of the soil sterilant problem is becoming apparent as more depleted oil and gas lease wells are abandoned. The seriousness of the problem has been identified by various provincial organizations and committees (17).

RRTAC recently completed a study addressing the emerging soil sterilant problem. The approach was to identify methods for binding the herbicide, thus rendering it ineffective. A greenhouse study was conducted to investigate the efficiency of activated charcoal for inactivation of bromacil and tebuthiuron residues in soil. Oats was used as a bioassay species to assess the phytotoxicity of bromacil and tebuthiuron residues.

Results of this greenhouse study showed that activated charcoal, at ratios of 1:200 or more (herbicide active ingredient:activated charcoal), can be effectively used to inactivate bromacil and tebuthiuron residues in soil. The efficiency of treatment depends on activated charcoal ratios, soil characteristics (texture, organic matter content and moisture level) and the time interval between activated charcoal incorporation and plant establishment (18).

Currently, a consultant is interviewing industry and government personnel to help identify specific field problems that can be addressed through research. Arising from this process will be an integrated research program that we can implement, or direct to other suitable funding agencies.

Compaction

Mining, pipelining and the construction of oil and gas leases all result in soil compaction. In fact, a recent report by the United States Office of Technology Assessment found that soil compaction was the single biggest problem in reclaiming cropland disturbed by mining (19). A survey conducted by RRTAC found that Reclamation Officers perceived soil compaction to be the prime concern in reclaiming oil and gas wellsites.

Repeated passage of heavy equipment during development and operating phases of a wellsite or pipeline results in compaction of the soil. Compacted soil retards root development which can lead to moisture and nutrient stress in plants. This, in turn, retards shoot development and yield. Freeze/thaw and wetting/drying cycles were thought to loosen compacted soil, but current evidence suggests that their benefits are rather limited. In Alberta, moderately compacted soils can have recovery times measured in decades.

There is a paucity of useful data pertaining to soil compaction in Alberta (and elsewhere), largely because a fully satisfactory measurement technique has yet to be identified. Crop yield is the best measure of compaction in addressing agricultural concerns. However, the effect of soil compaction on crop yield varies with soil type, yearly meteorological conditions, and type of crop. It is hoped that a measurement of compaction must be identified that has a high correlation with plant response, is independent of soil type, is inexpensive, and can be performed rapidly in the field.

Bulk density is most commonly used to determine soil compaction, but shows considerable natural variation due to soil particle size distribution and organic matter content, and has no unique value at which root growth is impeded. Hydraulic conductivity, porosity, air permeability, infiltration, and sorptivity yield valuable information about the effect of compaction on physical processes

in soils. But these are not suitable as operational field measurements due to long measurement times, wide data variability, departure from normality, and the absence of an exact relationship between these properties and plant growth.

Our initial approach to the compaction problem was to determine what characteristics predispose a soil to compaction and to identify the best field method for identifying and quantifying compaction. This knowledge will allow operators to avoid compaction wherever possible and allow regulatory personnel to identify compacted areas. A cone penetrometer, developed at the Alberta Environmental Centre, allows mechanical impedance to be measured at various depths in the field at extremely low cost.

Using the penetrometer, a detailed survey of wellsites was conducted in east-central Alberta. It concentrated on establishing appropriate sampling densities and on evaluating various techniques of measuring compaction. At five wellsites, data were collected on soil strength (recording penetrometer), undisturbed cores were collected for measurement of bulk density and pore size distribution, disturbed or undisturbed cores were collected for measurement of moisture content, texture and organic matter, and soil profiles (for classification) and soil morphology were recorded.

The second part of the study involved an assessment of soil compaction on 20 wellsites using a recording penetrometer to measure vertical and horizontal soil compaction profiles. Emphasis was placed on strength measurements because they can be taken quickly, no expensive and time consuming laboratory work is required, and work at the Alberta Environmental Centre and elsewhere suggests that soil strength may be the variable most closely related to plant growth in compacted soils.

The information generated by this research will be published in 1990. It has helped determine the nature and scope of the compaction problem, and establish appropriate methods and sampling designs for future work concerning compaction.

Our Reclamation Officers are now equipped to measure compaction at any disturbed site. However, there is little information relating mechanical impedance or any other measurement to reductions in crop yield. What is needed is a simple model for routine applications that predicts plant yield with a minimum of data input.

The main objective of the third phase of the research is to identify the relationship between subsoil compaction, topsoil depth, and plant productivity under a range of conditions (soils and years). The experiment is factorial and arranged in a completely randomized design, with three compaction levels and four topsoil depths. Each treatment is replicated four times at each of two sites: a Chernozem soil, which was constructed in 1989; and a Luvisol, which was constructed in 1990. Barley will be grown in each plot for three years, and the growth response (measured by root biomass, root length, shoot biomass, and crop yield) will be related to three measures of soil compaction (penetration resistance, bulk density, and porosity).

The project is in its second year of data collection and is expected to go on for at least two more years. A final report is expected in 1994.

Conclusion

The oil and gas industry is an important facet of Alberta's diversified economy. Government and industry in the province have made a commitment to ensuring that this industry will continue to thrive while not harming the environment. Through the actions of the Oil and Gas Reclamation Research Program, we are making important strides toward this goal.

The cooperative efforts between government and industry are what makes the program so effective. As the program becomes established, and the partners become more comfortable with each other, we expect that we will be able to report many more successes.

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ALTERNATIVE PROCESSES FOR THE REMOVAL OF OIL FROM OILFIELD BRINES

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Introduction

Production of oil from both onshore and offshore oil recovery operations generates substantial volumes of oilfield brines which must be handled in an environmentally sound manner. Removal of residual suspended oil is a critical step in the handling and treatment of these brines prior to their ultimate fate which may be reinjection, deep well disposal, recycle or discharge to the receiving aquatic environment.

Conventional treatment of oilfield brines for oil removal generally involves the use of unit processes designed to separate the oil by gravity (or enhanced gravity) settling. These processes include skim tanks (ST), parallel plate separators (PS) and induced gas flotation units (IGF). In some instances, such as in onshore in-situ heavy oil recovery operations using steam, a polishing step, consisting of granular media filtration (GMF), is used for fine oil removal. The use of these processes is typical of both the offshore and onshore oil production in all major oil producing regions of the world. However, these processes have certain inherent features which make them prone to serious operating difficulties. Therefore, at some locations they can not be relied upon to consistently provide the degree of oil removal necessary to meet the specifications for recycle or discharge. Consequently, alternative oil removal processes need to be considered to treat the oilfield brines more effectively than is possible with the conventional processes.

Environment Canada's Wastewater Technology Centre (WTC) has been evaluating several aspects of oil removal from oilfield brines from both offshore oil production and from onshore in-situ heavy oil production using steam injection methods. This paper presents an overview of the status of conventional and alternative oil removal processes based on the results of the WTC work as well as other published information.

Requirements for Oil Removal from Oilfield Brines

The requirements for the treatment of oilfield brine vary depending on whether the brine is from offshore or onshore oil production and whether or not the brine

can be disposed of through deep-well injection.

Offshore Oil Production

Discharge of treated brine to the ocean is currently the most common approach for handling the oilfield brines at offshore oil production facilities. Before treatment, the oil concentration in the brines at these facilities can be as high as 400 mg/l or more[1]. On the other hand, present limits for oil concentration in the oilfield brine for marine disposal range from as low as 30 mg/L[1] in Australia to 48 mg/L[1] in the United States. The discharge limit in the North Sea is 40 mg/L[1]. Proposed guidelines for Canadian offshore platforms also specify a discharge limit of 40 mg/L[2]. The regulations for the North Sea[3] will shortly be revised, and lower discharge limits may be established for offshore oil production in this region.

Onshore In-Situ Heavy Oil Production

A significant portion of the heavy oil in Alberta and Saskatchewan is recovered using steam injection methods. These methods usually generate substantial quantities of oilfield brines. One approach for handling these brines is to recycle them as feed to the once-through oilfield steam generators. Since this approach is considered environmentally more attractive than the alternatives (such as deep well injection), the emphasis in the heavy oil industry is towards recycling as much brine as the circumstances would allow. However, certain factors (e.g. presence of other contaminants; experimental nature of the in-situ recovery facilities, etc.) currently mitigate against the recycle at most of the locations in Alberta and Saskatchewan, so that the oilfield brine is generally disposed of by deep well injection in these areas.

Concentration of oil in the untreated brines can be as high as 1 570 mg/L[4] or more. Recycling of the oilfield brine to generate steam requires that the suspended oil be removed down to non-detectable levels (< 1 mg/L)[5]. The specifications on the concentration of oil in the oilfield brines for deep well disposal are variable; however, it is generally acknowledged that minimizing the oil concentration in the brine to low levels is desirable to prevent plugging of the injection formation.

WTC Study on Offshore Oilfield Brines

In 1987, the WTC initiated a study to assess the status of oil removal technologies for oilfield brines from offshore oil production and to identify research needs related to the treatment of these brines. The study included a survey of offshore oil platforms in the North Sea. Questionnaires were forwarded to all major offshore oil platforms in the British and Norwegian sectors of the North Sea. Information was requested on the volumes of oilfield brine generated, disposal methods, type of oil removal processes used, typical performance of these processes and operational problems experienced with the oil removal process equipment.

Scope of the Survey

Responses were received from all the 17 oil companies contacted. Information was

provided for 43 platforms; 18 in the Norwegian sector and 25 in the British sector. Except for 2 platforms where reinjection of the oilfield water was carried out, all the platforms discharged the treated oilfield brine to the sea. The volume of oilfield brine generated at these platform ranged from 20 to 25 000 m^3/d with an average of 5 000 m^3/d.

Oil Removal Processes Identified

Table 1 shows the types of oil removal processes used and the number of platforms where each process was used. The most common processes used for both the Norwegian and British Sectors were plate separators and induced gas flotation units. Table 2 shows the most common process treatment trains used for each sector of the North Sea. In the Norwegian sector, the most common treatment train consisted of a skim tank, followed by a plate separator followed by an induced gas flotation unit. In the British sector, the most common process train involved the use of a plate separator alone or in combination with an induced gas flotation unit. The survey also identified (see Table 1) that the hydrocyclone, a relatively newer technology, was being used on five platforms in the British sector and was scheduled for installation on four platforms in the Norwegian sector.

Performance of Oil Removal Processes

Table 3 summarizes the average oil concentrations in the effluent from the various treatment processes. The influent oil levels seen by the process units were not determined by the survey. Of most interest is the effluent from the final process units prior to marine discharge of the oilfield brine.

The IGF unit was used as the final treatment process on 21 offshore installations. The average effluent oil concentrations ranged from 15 to 100 mg/L. However, the overall average oil concentration was less than 40 mg/L. In some cases (8 platforms), plate separators were used as the final treatment prior to discharge. In these cases, the overall average effluent oil concentrations was 15 mg/L with a range of 2 to 35 mg/L. Hydrocyclones typically produced an effluent averaging 33 mg/L of oil with a range of 13 to 75 mg/L.

Generally, the process units met the regulatory requirements; however, there were some instances of excessive oil concentration in the effluent as a result of operating problems experienced with the treatment process.

The main operating problems identified from the WTC survey for the plate separator, the IGF unit and the hydrocyclone are summarized in Table 4. The most commonly cited problems for the IGF unit were the inability to handle emulsions and the inability to maintain good level control. These operating difficulties caused very high concentrations of oil in the final effluent; in several of the responses, maximum oil concentrations over 2 000 mg/L were cited. These problems have also been identified at the oil production platforms operating in the U.S.[6]. The frequency of occurrence of these upsets was not identified in the survey conducted by the Wastewater Technology Centre; however, other data[6] suggest that upsets could occur about 20-30% of the time. Similar problems were experienced with the operation of the plate separators. For the hydrocyclone, no

difficulties were cited with respect to platform motion or high oil levels in the influent to the treatment train, but problems were experienced with erosion and sand buildup. The offshore operators also indicated that effective on-line oil-in-water monitoring of the treatment processes would be helpful in achieving a more consistent performance than is currently observed.

Conclusions from the WTC Study on Offshore Oilfield Brines

From the WTC study, it was concluded that although the plate separator and IGF units were the most common processes used on North Sea platforms, there were substantial operational problems associated with these units. The relatively newer hydrocyclone technology seemed promising because of lower sensitivity to platform motion and to variable influent oil concentration. For the Canadian situation, where full scale offshore oil production is not yet in place, hydrocyclones would appear to be the most appropriate technology for removing suspended oil from the produced brines.

WTC Study on Onshore In-Situ Heavy Oil Recovery Brines

In 1988, the WTC conducted a study to evaluate the performance of oil removal processes operating at two in-situ heavy oil recovery operations (Sites A and B) in Alberta. Long term and intensive sampling campaigns were conducted at each site. During the long term sampling campaign, samples were collected daily over a one month period to monitor long term performance variations. The intensive sampling campaign, consisting of 4 to 5 samples per day, was conducted over a 1 week period to monitor daily performance. Grab samples of process feed and effluent streams were taken for determining the oil concentration in the sampled streams. The analytical method for determining oil was based on a standard partition/gravimetric method using Freon 113[7].

Figures 1 and 2 schematically show the oil removal process trains and the sampling locations for the oilfield brines generated at Sites A and B respectively. At Site A, the oil removal process train consisted of a skim tank, an IGF unit and three anthracite/garnet filters. The capacity of the IGF unit was less than the volume of water produced so that up to 20 % of the water bypassed the unit and was introduced directly to the filters. The total flow of produced water was 6 000 m^3/d at this site, and the water was disposed of by deep well injection. At Site B, the oil removal process train consisted of a skim tank, a surge tank, an IGF unit and two sand filters. In this case, 2 000 m^3/d of oilfield brine was being treated prior to deep well disposal.

Results from the In-Situ Onshore Study

Tables 5 and 6 present a summary of the results of the performance evaluation study for Sites A and B respectively.

At Site A, the effluent oil concentration from the IGF unit averaged 47.9 mg/L and 25.1 mg/L during the daily and intensive sampling programs respectively. Wide variations in the long term performance of the IGF unit were observed, as indicated by the high standard deviation in the oil and grease concentration (see Table 5 and Fig.1). Considerable problems were experienced with the operation

of the anthracite/garnet filters at Site A. The average oil concentration for the filter effluent during the intensive sampling campaign was 40.5 mg/L; this corresponded to an oil removal efficiency of only 6.7%. Main operating problems experienced with these filters included channelling, and "mudballing" of the filter media. The filters were frequently out of operation because of these difficulties.

At Site B, long term performance for the IGF unit was worse than that observed for the IGF unit at Site A. The average IGF effluent concentration for Site B was 101.2 mg/L. During the study period, the skim tank had been shut down and the surge tank was being used as a skimming vessel. The loss of surge capacity resulted in high flow and oil level variations in the IGF feed. As at Site A, wide variations in IGF performance were observed as shown in Fig.4. During the intensive campaign, the IGF performance at Site B was comparable to that of the IGF unit at Site A. For the sand filters at Site B, the effluent oil concentration averaged 51.4 mg/L for the long term sampling campaign and 25.8 mg/L for the intensive sampling campaign. The poor performance of the sand filters over the long term is attributed to frequent oil leakage due to channelling in the filter. The average oil removal efficiency of the sand filters at Site B over the long term was only 8.4%.

Conclusions from the In-Situ Onshore Study

The study identified substantial operational problems with the conventional IGF and GMF units. These problems result in wide variations in effluent quality and oil removal efficiency over time; effects that would severely limit the ability of the heavy oil operators to recycle the oilfield brine. Therefore,it was concluded that alternative processes need to be evaluated in order to obtain the consistently high quality effluent that is required for recycle to the steam generators.

Alternative Processes for the Removal of Oil

Since the completion of the WTC work described above, there have been significant developments in the oil removal process technologies for the treatment of oilfield brines. These developments relate to the increased use of hydrocyclone processes and the field testing of membrane technologies (ultrafiltration and microfiltration) to alleviate some of the operational difficulties previously described. The following paragraphs detail these alternative processes and their status for both offshore and on-shore in-situ heavy oil recovery situations.

Hydrocyclone

Potential advantages of hydrocyclones over the conventional oil removal processes for the treatment of oilfield brines from offshore oil platforms are (i) relatively low weight and volume requirement, (ii) insensitivity to wave motion, and (iii) reduced sensitivity to influent oil concentrations.

The operation of the hydrocyclone is based on the use of a swirling flow pattern to generate centrifugal forces which separate the oil and water based on their density difference. There are two types of hydrocyclones which are distinguished

by the method used to generate the flow pattern. In static hydrocyclones, the swirling flow pattern is established by high inlet flow and pressure; in rotary hydrocyclones, mechanical rotation provides the swirling flow motion. The main advantage cited by the manufacturer of the rotary hydrocyclone is that high inlet velocity is not needed and high turndown ratios are possible. Both units are subject to erosion by sand usually present in the oilfield brines. Figures 5 and 6 show schematics of the static and rotary hydrocyclones respectively.

Currently, hydrocyclone applications are limited to the treatment of offshore oilfield brines, and full scale static hydrocyclone systems have been installed at more than 50 offshore platforms[8]. One rotary hydrocyclone system is being installed offshore in Holland[9]. The static hydrocyclone is now marketed by Conoco Special Products Inc. (CSPI) in the U.S. The rotary hydrocyclone, which is a relatively newer technology, is being marketed by Serck Baker U.K. under the name "Dynaclean". Published data on the performance of the Dynaclean unit are limited. However, results of tests[10] conducted in 1989 at an independent testing centre in Northern Scotland indicate that, at an inlet oil concentration of 150 mg/L, the Dynaclean can consistently generate an effluent containing less than 40 mg/L oil, and maintain this performance at flow rates ranging from 20 to 200 % of the nominal design flow rate. In these tests, the oil removal efficiency of the rotary hydrocyclone remained near 90 % when the inlet oil concentration was increased from 20 to 1 800 mg/L.

The CSPI static hydrocyclone has been tested for heavy oil field application in Alberta[11] but results of these tests have not been released. The Dynaclean rotary hydrocyclone has not been tested in the field for the treatment of oilfield brines from in-situ operations in Alberta or Saskatchewan.

Membrane Technology

Potential advantages for application of membrane processes (ultrafiltration and microfiltration) to oilfield brines for offshore platforms include (i) low size and weight, (ii) insensitivity to platform motion, (iii) insensitivity to fluctuations in influent oil concentration and (iv) more consistent effluent quality. The last two factors are also relevant to onshore in-situ heavy oil operations.

Figure 7 shows a schematic of the principle of operation of membrane filtration processes such as ultrafiltration (UF) and microfiltration (MF). The oil containing brine flows axially in a porous tube while the clean water flows radially through the tube walls. MF implies tube wall pores in the range of 0.1 micron to a few microns. UF, on the other hand, implies much finer pores (<0.01 μm). Because of the positive barrier available for separating the oil from the water, the effluents generated by UF and MF processes are expected to be virtually free of suspended oil. The flux (flow rate per unit membrane area) is generally higher for MF than for UF; however, MF can be more susceptible to particulate fouling than UF. UF and MF membranes may be made from a number of organic polymers or inorganic materials. The commercial organic membranes are available in a wide range of polymers including cellulose acetate, cellulose triacetate, polysulphone, polypropylene and polyimide. Similarly, commercial

inorganic membranes are available in many different materials including alumina, zirconium oxide, titanium oxide, stainless steel and carbon.

For MF and UF treatment of oilfield brines, several tubular membranes are generally placed in tubular modules to provide high surface area for filtration. A system consists of many of these modules, a recirculation pump and ancillary tanks for feed, concentrate and product. A schematic of a typical assembly is provided in Fig. 8.

Microfiltration has been tested for both offshore and heavy oil field applications. One MF system for the treatment of oilfield brines is currently marketed by Alcoa in the U.S. The system uses tubular alumina membranes and employs a permeate backflush to maintain the membrane flux. Discussions with the supplier indicate that pilot tests (up to several months long) have been conducted in the North Sea and the Gulf of Mexico, and a full-scale Alcoa system is currently being installed on an oil production platform in the Gulf of Mexico[12]. Published data on the performance of MF systems and on the testing of any UF systems for offshore oilfield brines are currently not available. However, both UF and MF have been tested for the treatment of oilfield brines from in-situ heavy oil recovery operations in Alberta at bench and pilot scale, and some data are available for this application of UF and MF.

In 1981, the Alberta Oil Sands Technology and Research Authority (AOSTRA) funded a study[13] on the evaluation of UF for removal of oil from the oilfield brines. However, the results of this study are not available in the open literature. Later work on UF[14] for oil removal on oilfield brines from in-situ heavy oil recovery operations consisted of off-site and on-site trials at bench and pilot scale. These tests were conducted with a UF system and two different membranes developed by Zenon Environmental Systems, Burlington, Ontario. Initial trial runs (several days to a few weeks) indicated that an effluent flux ranging from 50 - 250 $L/m^2/h$ could be achieved with cleaning intervals ranging from 1 to 7 days. Longer term pilot tests[15] (total of 2 months/membrane) conducted in 1989/90 indicated that under certain conditions substantially lower fluxes were attained. This flux decline was attributed to fouling due to the presence of fine solids in the oilfield brines. The presence of certain oil-well treatment chemicals in the the brine also caused the leakage of suspended oil through the membranes. During most (approximately 80 %) of the test period, however, these problems did not appear and a high quality effluent (negligible suspended oil) was generated by UF.

MF work on oilfield brines from in-situ heavy oil operations has been conducted at both bench and pilot scale at research facilities and in the field. Most of the tests have been short term [16] (a few days to 2 weeks). In one widely tested system, developed by Separ Systems and Research Ltd., Calgary, Alberta, chemicals (such as ferric chloride, calcium oxide and sodium carbonate solely or in combination) are added to the oilfield brine and recirculated through Alcoa ceramic membranes. Available data from one of these tests indicated fluxes ranging from 800 - 1 800 $L/m^2/h$ [16]. In longer term pilot tests[15] (total of 5 months testing) conducted in parallel with the UF pilot test cited previously,

the flux was substantially less than what was observed in the short term trials. No substantial difference in the flux rate was observed between trial runs conducted with and without the use of chemical addition. One MF system is currently being installed at an onshore oilfield site in Alberta[12].

Studies of membrane technology have identified several difficulties. However, it must be recognized that the work completed to date has been limited both in terms of scope and duration. There are many membrane materials and systems currently available that are potentially suitable for application to oilfield brines. In addition, longer term testing is required to determine the performance of membrane processes under the range of conditions seen over time at operating oilfield sites.

Overall Conclusions on Conventional and Alternative Oil Removal Processes

There is an increasing need for reliable and efficient technology for the removal of oil from oilfield brines generated from the onshore and offshore oil production. Treatment requirements must address the prospect of more stringent limits for marine discharge of the oilfield brines from offshore oil platforms, and for the recycle of oilfield brines from heavy oil production.

The survey of the North Sea offshore oilfield treatment systems and the performance evaluation study of conventional processes in Alberta heavy oil fields indicated serious operating difficulties with conventional processes (IGF, granular media filters, etc.) which led to inconsistent effluent quality.

Hydrocyclones and membrane processes have certain advantages over the conventional oil removal technology. These advantages include insensitivity to platform motion, low load requirements, reduced sensitivity to variable influent oil concentration and consistent effluent quality.

The WTC tests on MF and UF at a heavy oil field site in Alberta indicated generally consistent performance but did not generate sufficient long term data to allow an evaluation of the cost effectiveness of the membrane processes.

Ongoing Research Activities at WTC

For Canadian offshore oilfield brines, studies to evaluate the performance of both the static and rotary hydrocyclone are currently in progress. In addition, evaluation of several oil-in-water monitors and analytical methods for oil determination is currently ongoing. Also, there are plans to initiate, in the Fall of 1990, a systematic evaluation of up to 20 commercially available and experimental membranes for their suitability for application to the treatment of oilfield brines from in-situ heavy oil recovery operations in Alberta.

Acknowledgement

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TABLE 1

Oil Removal Equipment on North Sea Platforms

Unit	Norwegian Sector	British Sector	Overall
Skim Tank	11	3	14
Plate Separator	12	15	27
Induced Gas Flotation	15	12	27
Hydrocyclone	4*	5	9
Coalescer	1	1	2
Granular Media Filter	0	1	1
Dissolved Air Flotation	0	1	1
Other	4	3	7

* scheduled for installation

TABLE 2

Oil Removal Treatment Trains on North Sea Platforms

Process Train	Norwegian Sector	British Sector	Overall
ST/PS/IGF	8	1	9
PS only	1	7	8
IGF only	3	3	6
HC only	4*	2	6
PS/IGF	1**	4	5

* installations not complete at time of survey
** combination skim tank and plate separator

TABLE 3

Average Effluent Oil Levels from North Sea Platform Survey

Process	Norwegian Sector #	Range	Mean	British Sector #	Range	Mean	Overall #	Range	Mean
ST	10	15-3000	882	2	200-3000	1600	12	15-3000	1001
PS	11	20- 200	163	13	2- 220	47	24	2- 220	51
PS*	1		20	7	2- 35	14	8	2- 35	15
IGF	14	15-2000	174	11	16-2000	217	25	15-2000	193
IGF*	13	15- 38	33	8	16- 100	38	21	15- 100	35
HC*				5	13- 75	33	5	13- 75	33

* used as final treatment prior to marine discharge

TABLE 4

Main Operating Problems of Oil Removal Equipment On North Sea Platforms

Plate Separator	Induced Gas Flotation	Hydrocyclone
Plugging of plates	Unable to handle emulsions	Erosion and corrosion
Unable to handle emulsions	Level control problems	Blockage due to sand buildup
Platform motion	Platform motion	
Oil slugs	Oil slugs	
Surge loads	Poor froth formation	
	Interference by treatment chemicals	
	Poor mechanical durability	
	Scale/sludge buildup	
	Operator/maintenance intensive	

TABLE 5

Performance of Oil Removal Units at Site A

Unit	Sampling Campaign	Number of Samples	Total Oil Concentration(mg/L)				Oil Removal (%)	
			Influent		Effluent			
			Mean	S.D.	Mean	S.D.	Mean	S.D.
IGF	Long Term	25	85.9	39.1	47.9	18.2	40.9	20.0
	Intensive	19	76.9	40.5	25.1	2.8	57.1	22.0
GMF	Intensive	21	45.1	16.3	40.5	25.1	6.7	53.0

TABLE 6

Performance of Oil Removal Units at Site B

Unit	Sampling Campaign	Number of Samples	Total Oil Concentration(mg/L)				Oil Removal (%)	
			Influent		Effluent			
			Mean	S.D.	Mean	S.D.	Mean	S.D.
IGF	Long Term	20	112.3	97.6	101.2	87.3	7.9	37.7
	Intensive	20	155.3	206.9	45.3	43.2	52.7	22.9
GMF	Long Term	18	129.2	108.5	51.4	34.0	42.2	36.6
	Intensive	19	40.0	32.8	25.8	13.7	8.4	50.0

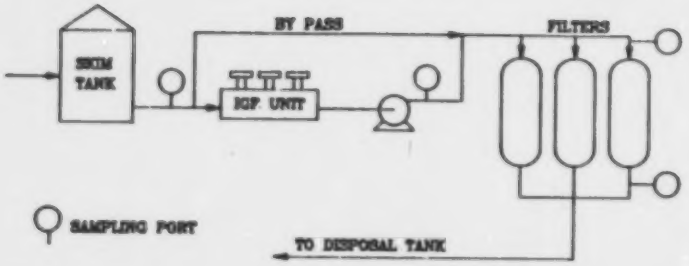

Figure 1 Site A Process Flow Schematic

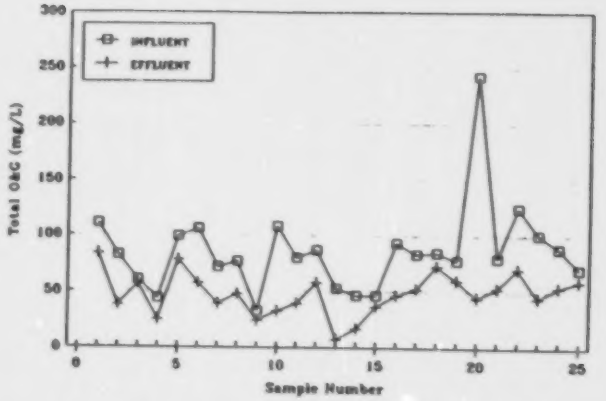

Figure 3 Long Term IGF Performance at Site A

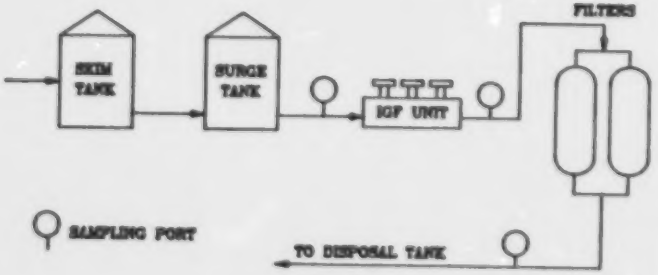

Figure 2 Site B Process Flow Schematic

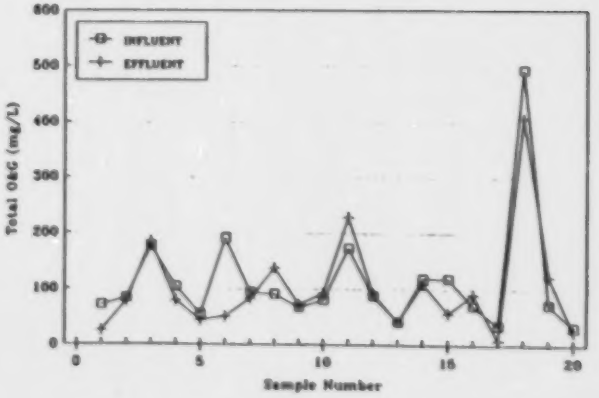

Figure 4 Long Term IGF Performance at Site B

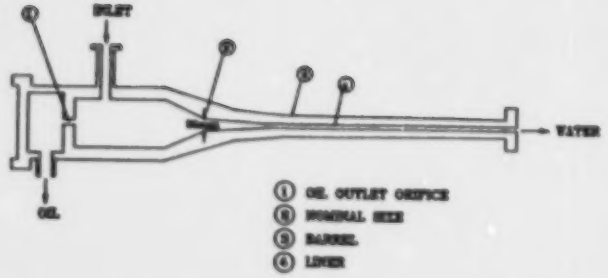

Figure 5 Description of static hydrocyclone

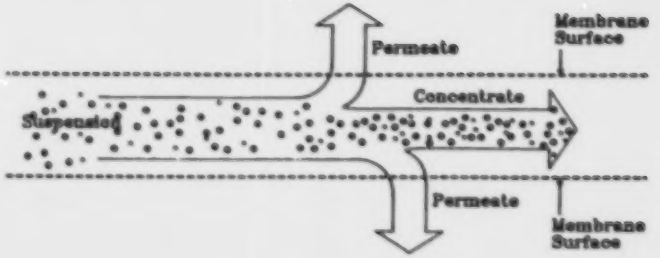

Figure 7 Schematic of Crossflow Filtration Processes

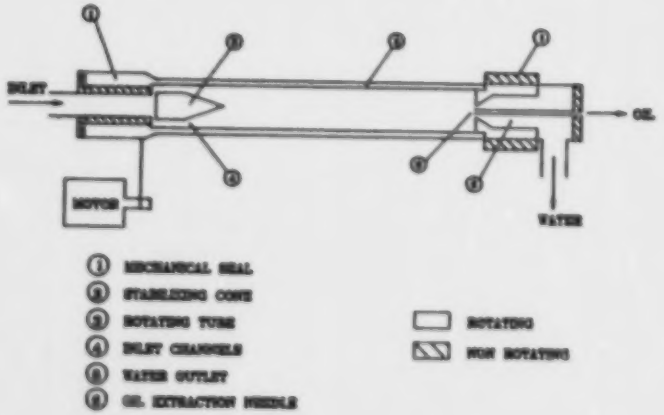

Figure 6 Description of Rotary Hydrocyclone

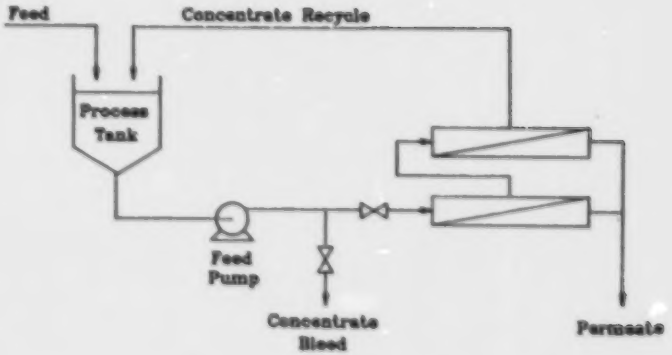

Figure 8 Typical Process Schematic of Crossflow Filtration

AN ASSESSMENT OF PRODUCED WATER IMPACTS TO LOW-ENERGY, BRACKISH WATER SYSTEMS IN SOUTHEAST LOUISIANA: A PROJECT SUMMARY

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Introduction

Produced water is a by-product of the oil production process and is brought to the surface along with petroleum from subsurface formations. Also known as formation water or oil field brine, produced waters associated with Louisiana oil reserves are usually highly saline with ranges reported by Hanor *et al.* (1) from 50 ppt to 150 ppt. In comparison, the average open-ocean salinity is 35 ppt (2). Louisiana inland water salinities vary considerably with distance from the Gulf of Mexico, but are almost always much less than those found in the open sea.

Produced waters can also contain various radionuclide and volatile and semivolatile organic hydrocarbon contaminants. Boesch *et al.* (3,4) demonstrated that produced waters discharged into Louisiana waters contained high concentrations of petrogenic hydrocarbons. Sediments near these effluents were also highly contaminated with semivolatile organic hydrocarbons. Reid (5) surveyed several Louisiana produced water effluents and found radium 226 levels ranging from 131 ± 3 pCi/l to 393 ± 7 pCi/l.

The recently escalated research interest in the environmental effects of produced water discharges is largely based on increased regulatory concerns by various federal, state, and local agencies. These agencies have directed research efforts towards obtaining the data necessary for reassessing and updating current regulations dealing with produced water discharges.

Within the State of Louisiana, the Louisiana Department of Environmental Quality (LDEQ), Water Pollution Control Division, governs all discharges to surface waters. The current Louisiana regulations which specifically apply to produced waters date back to 1953. The 1953 rule basically allowed produced water effluents into any stream not used for drinking water purposes. In 1968 an additional rule was promulgated which prohibited the discharge of oil field brines into freshwater areas, but allowed for their release into "...normally saline waters, tidally affected waters, brackish waters, or other waters unsuitable for human consumption or agricultural purposes" (6).

On November 20, 1985, LDEQ adopted a water discharge permitting system which required all effluents, including those from the oil and gas industry, to be permitted. An agreement was made to allow the petroleum industry until May 20, 1986, to submit applications.

Data from the applications submitted by the petroleum industry were summarized in a study by Boesch and Rabalais (3). The total volume of produced water discharged to Louisiana waters at the time of the study was almost 2,000,000 barrels per day.

Generally, the objectives of this study were derived to further evaluate past observations made by the LDEQ staff and other investigators or to add to the available data base regarding produced water discharges to low-flow type systems. The specific study objectives are presented below.

1. To evaluate the hydraulic behavior of produced water effluents to poorly flushed brackish or saline systems.

2. To quantify the organic, inorganic, and radiological pollutants in selected produced water discharges and in proximate sediments and to evaluate the spatial extent of effects.

3. To evaluate the potential for bio-concentration of polynuclear aromatic hydrocarbons (PAH) from contaminated sediments by benthic biota.

4. To evaluate the biotoxicity of produced water effluents and proximate sediments.

5. To assess the potential for the accumulation of radionuclides and organic pollutants by caged oysters placed in proximity to produced water discharges.

Presented in this paper is a general summary of study results. The original study report which is presented in more detail is available from the study coordinator.

Study Sites

Four study sites in southeast Louisiana were selected for study. Study sites consisted of a single discharge and were located in the Lirette (LRT),

Delta Farms (DF), Bully Camp (BC) and Lake Washington (LW) Oil Fields. Three transects, labeled "A", "B", and "C", radiated from each produced water site outfall. Eight sample points were distributed at varying distances from the outfall along the transects. An unaffected reference sample point was selected for each study site for comparison.

The types of samples collected were either sediments, effluents, biota, or water column. Sediments and water column samples were collected from each transect sample point. Biota were collected from caged oysters placed along a site transect.

This study was meant to be a general assessment of the extent and nature of produced water impacts and therefore did not include the replications necessary for extensive statistical analyses.

Discharge volumes varied from 462 barrels per day (bpd) at the LRT site to 13,458 bpd at the DF site. Effluent salinities were considerably higher than receiving stream concentrations and ranged from 139 ppt at the LRT site to 193 ppt at the LW site. Receiving stream salinities ranged from about 4.0 ppt at the DF site to an average of 23 ppt at the LW site.

Hydraulic Behavior of Produced Water Effluents

Due to their high salinities, Gulf Coast produced waters are generally much denser than Louisiana inland waters. Harper (7) reviewed literature which reported a bottom layer of higher salinities near produced water effluents into poorly flushed canals. Boesch and Rabalais (3) concluded that produced water effluents can act as dense plumes after discharge to estuarine waters. Studies have also shown high concentrations of hydrocarbons in sediments near produced water outfalls (3,4,8). These observations, along with those made by Baird *et al.* (9) provided the impetus for this further investigation into the hydraulics of produced water effluents.

A slotted core tube was used to collect sediment and overlying water samples from each transect point for chlorides analyses. Overlying water was collected from the core tube at the sediment/water interface (0 level) and at the 10 cm (+10) and 20 cm (+20) levels. Interstitial water was also collected from 10 cm core sections (-10, -20, and -30 levels). Water column measurements were also taken with a commonly-used CTD (conductivity, temperature, depth) instrument.

Results from all 4 study sites (Figs. 1, 2, 3 and 4) indicated that produced water influences on chloride concentrations of the receiving water body were considerably more apparent in bottom sediments in comparison to those effects measured in the water column. At some stations highly elevated sediment chloride concentrations were measured, while no measurable impact in the water column of the same station was detected. This suggests that almost no apparent mixing of these discharges is occurring or that any dilution which might occur is insufficient to completely reduce the density differences between the produced water effluent and the receiving water column.

Produced water was shown to penetrate to a depth of at least 30 cm at some stations and there was a strong positive correlation between depth increases and interstitial chloride increases at the most impacted transect points. The trend of steadily increasing sediment chlorinities suggests that a produced water penetration to levels deeper than 30 cm is likely.

The highest interstitial chlorinities were measured at the stations nearest to the outfall (LRT-0, DF-0, BC-0, and LW-0) with progressively lessening effects noted at more distant transect points. The most heavily impacted sediments were visibly contaminated with high concentrations of hydrocarbons. Trend analysis of selected study site stations indicated an exponential rate of increase in sediment chloride concentrations as the origin is approached.

Study results also show that conventional CTD instruments may not be capable of consistently detecting produced water chloride impacts since much of the effect, at least in poorly flushed systems, may be below the position of the conductivity sensor. A strict reliance on water column salinity readings near produced water effluents might result in the erroneous conclusion that produced waters are completely mixed and quickly dispersed after discharge.

Radium 226 Activities in Produced Water

Produced waters from Louisiana and locations throughout the world have been shown to contain environmentally high concentrations of radium (5). The regulatory control of naturally occurring radioactive materials (NORM) has not received sufficient attention in the past by federal and state agencies because of limited jurisdictions and staff (10).

Current Nuclear Regulatory Commission regulations set a maximum radioactivity level of 30 pCi/l in liquid discharges from nuclear power plants to unrestricted access areas. Standards for drinking water are set not to exceed 5 pCi/l. EPA regulations proposed in response to the Resource Conservation and Recovery Act of 1976 (RCRA) would classify radioactivity levels of greater than 50 pCi/l as a hazardous waste. The natural radium 226 activity of Louisiana surface waters is usually below 1.0 pCi/l (10).

The USEPA and the Conference of Radiation Control Program Directors have recommended remediation of radium-contaminated soils to 5 pCi/g above background. The natural Ra 226 activity of Louisiana surface soils ranges from <1 pCi/g to about 7.0 pCi/g (10).

High radium 226 levels were detected in all study site effluents and ranged from a low of 355 pCi/l at the Delta Farms site to 567 pCi/l at the Bully Camp site. The variation between site effluent activities is probably due to differences in the mineral composition of the geologic formations from which petroleum is extracted (11).

The top 10 cm of sediment from each transect sample point were analyzed for radium 226. The sediments from the station nearest to the outfalls at the Lirette (Fig. 5), Bully Camp (Fig. 7), and Lake Washington (Fig. 8) study sites contained very high concentrations of radium 226 ranging from 182 pCi/g at the

Bully Camp transect origin to 533 pCi/g at the Lirette site transect origin.

Radium 226 levels in LRT, BC, and LW sediments located away from the outfalls were lower than transect origin sediments but were still elevated above background levels at most of the transect sample points. Stations indicating radium activities which were greater than 5 pCi/g above the site background (reference) were up to 500 meters from the outfall (Lirette site, Fig. 5).

Sediment accumulation of radium 226 at the Delta Farms site (Fig. 6) did not follow the observed pattern of the other sites. No accumulation of radium was noted in Delta Farms sediments. This was attributed to the predominantly organic nature of the sediments at this site. Radium 226 has been shown to be more effectively adsorbed by the fine-grained, clay type soils which were noted at the Lirette, Bully Camp, and Lake Washington sites (12,13).

Although only the top 10 cm of sediments were considered in this study component, there was evidence which suggested that radium 226 contamination in sediments near the produced water outfalls investigated may increase with depth as did the interstitial chloride concentrations. An excavated 50 meter station, LW-B50, at the Lake Washington site showed higher radium 226 activities than another, undisturbed 50 meter station (Fig. 8). It also appeared that the excavation may have allowed for the transport of radium contaminated sediment to more distant transect stations.

Biotoxicity

Samples of each study site effluent were tested for acute toxicity to mysids and sheepshead minnows. Sediments from a station near each site effluent and a reference from each study site were also tested for acute toxicity using an elutriate and a solid phase procedure.

Each effluent exhibited 96 hour acute toxicities to mysids which was attributed to components other than salinity. The Lirette effluent was the least toxic to mysids with an LC_{50} value of 5.8% effluent. The highest mysid effluent toxicity was measured at 2.6% effluent in the Bully Camp discharge sample. The mean LC_{50} for all effluents was 4.3%.

Effluent toxicity patterns using sheepshead minnows differed from mysid test patterns and sheepshead minnows were shown to be less sensitive to produced water effluents. The 96 hour LC_{50} values for sheepshead minnows ranged from 33.8% effluent (least toxic) at the Bully Camp site to 7.2% effluent (most toxic) at the Delta Farms site. The mean 96 hour LC_{50} value for all effluents used in sheepshead minnow tests was 20.1%.

Two methods were used to measure sediment toxicity. The first method used tested the toxicity of a sediment elutriate to mysids. The elutriate tests failed to show any significant acute toxicity.

The second sediment toxicity method used was a solid phase procedure which measured the toxicity of sediment samples to the borrowing amphipod, *Hyalella azteca*. Significant levels of acute toxicity to *Hyalella*, due to a component

other than salinity, were measured using this solid phase procedure. The mean mortality rate for all treatment sediments was 73.3% mortality. One study reference sediment sample, BC-R, demonstrated a significant mortality rate (28.9%). The remaining reference sites showed no significant mortality.

Chemical Characterization of Produced Water Impacts

The chemical composition of four produced water discharges were characterized using gas chromatography/mass spectrometry for the identification and quantification of the organics and inductively coupled plasma/mass spectrometry for the quantification of the trace metals. The produced waters were characterized by high concentrations of volatile, including benzene and toluene, and semivolatile hydrocarbons such as aliphatic hydrocarbons and a series of alkylated polycyclic aromatic hydrocarbons (primarily naphthalenes and phenanthrenes). The discharges also contained high concentrations of aromatic acids and aliphatic fatty acids. The trace metal content of the four discharges was very variable, however, each was characterized by high levels of barium, ranging from 1,521 ppb in the Delta Farms produced water discharge to a maximum of 4,644 ppb in the Lirette field discharge. Vanadium, a trace metal often associated with oil, was also found in each of the four discharges at variable levels. Some discharges contained significant levels of arsenic and copper. These levels of toxic metals and organics represent a significant negative impact upon receiving waters of natural bayous because of the high volumes of formation waters discharged annually into confined waterways which are often poorly flushed by freshwater flow or tidal exchange. Because of the hydrology of these systems and the particle reactive nature of both the metals and organics being discharged, we would anticipate that these substances would continue to accumulate within the sediments in the region of the discharges to high levels.

Assessment of Produced Water Chemical Impacts to Receiving Streams

The impacts of produced water discharges on sediment quality varied in each of the areas studied (Fig. 9). Major factors determining the degree of impact were: 1) discharge rate; 2) quantity and quality of the hydrocarbons and trace metals present in a particular discharge; 3) local hydrology; 4) sediment disturbances (i.e. dredging and boat traffic); and 5) sediment types (organic carbon content and texture). Analyses of sediments collected at the four sites revealed that all four receiving water systems were measurably impacted by the discharges in the region. Concentrations of both aliphatic and alkylated aromatic hydrocarbons characteristic of the discharges, as well as barium, were found at elevated levels above background in the sediments surrounding the discharges. The areal extent of this contamination expressed in terms of a Fossil Fuel Pollution Index (14) or Ba concentration was found to extend to the farthest points sampled at each discharge site (about 300m). The continuation of these discharges into these receiving waters will likely result in an increase in both the level and extent of contamination at these sites.

Investigations of the genotoxic potential of the produced water carried out in other studies indicated that chemicals in produced waters represent a significant genetic risk to embryo and larval stages of fish (15). In this study a bioaccumulation model applied to the levels of contamination found in the

sediments yielded extremely high potential tissue burdens for benthic invertebrates, including edible species. Thus, these chemicals represent both a potential ecological and human health risk.

Accumulation of Organics and Radium 226 by Oysters

The use of bivalves in bioaccumulation studies has been advocated by researchers from several scientific disciplines (16). Oysters have been shown to accumulate hydrocarbons from produced water effluents (17,18,19). Jeffree and Simpson (20) demonstrated that freshwater mussels can accumulate radium 226 from uranium mill effluents. There have been no known investigations into radium 226 accumulation potentials by the oyster, *Crassostrea virginica*.

In this study component, caged oysters were used to assess the potential for the uptake of organic contaminants and radium 226. Oyster cages containing 75 individuals each were placed at the Lirette, Bully Camp, and Lake Washington sites. Lirette cages were 110 meters from the outfall and Bully Camp and Lake Washington cages were placed 85 and 70 meters, respectively, from produced water outfalls. A control was deployed at an unaffected location in Caillou Lake. All oysters remained in place for 30 or 33 days.

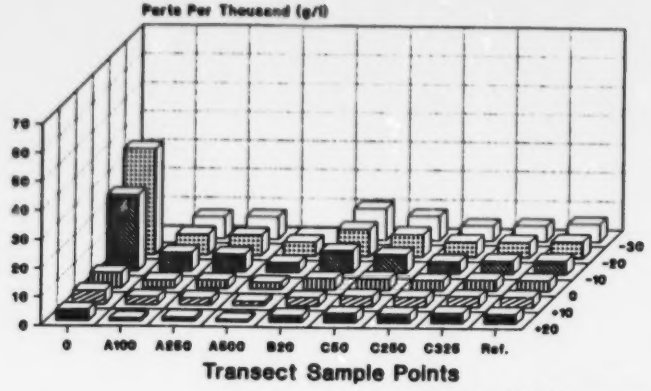
All of the oysters exposed to produced water impacts in this study component accumulated volatile and semivolatile organic compounds. The control site oysters accumulated no volatile organics and only trace quantities of pyrogenic semivolatiles. Total tissue volatiles among treatment site oysters ranged from 3 ppb at the Lake Washington site to 372 ppb in tissues from the Lirette site. Of all volatiles measured, toluene was detected in the greatest quantity. Petrogenic polynuclear aromatic hydrocarbons were detected ranging from 41 ppb at the Lirette site to 319 ppb at the Lake Washington site.

Radium 226 analysis of caged oyster tissues indicated that oysters growing near produced water effluents may accumulate petrogenic radionuclides. Tissue samples from oysters placed near the Lirette effluent accumulated 3.1 ± 0.3 pCi/g of radium 226. Oysters placed at the Caillou Lake reference and Bully Camp and Lake Washington study sites accumulated no measurable radium activities.

Several studies have shown that oysters can release accumulated hydrocarbons after exposure in contaminant-free water (17,18). Oysters are usually harvested directly, however, and are not depurated before being consumed. This must be considered when assessing the potential for human health risks associated with chemically contaminated shellfish.

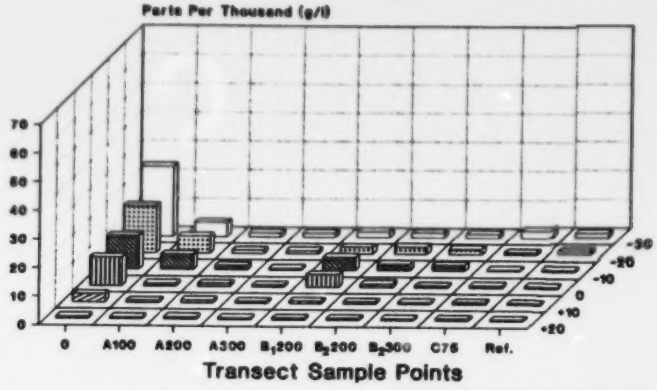
Studies by Jeffree and Simpson (20) related to uptake of radium 226 by freshwater bivalves show that these organisms can readily accumulate these pollutants in a linear manner from water containing radium at levels which were much less than those measured in the four outfalls studied. A complete in-depth study would be needed to assess the full radiological impact of produced waters on oysters. Such a study is recommended since many of these discharges currently exist near commercial oyster harvesting areas.

Fig. 1. Cl Results of Interstitial Water From Sectioned Cores and Overlying Water Strata at all LRT Site Stations



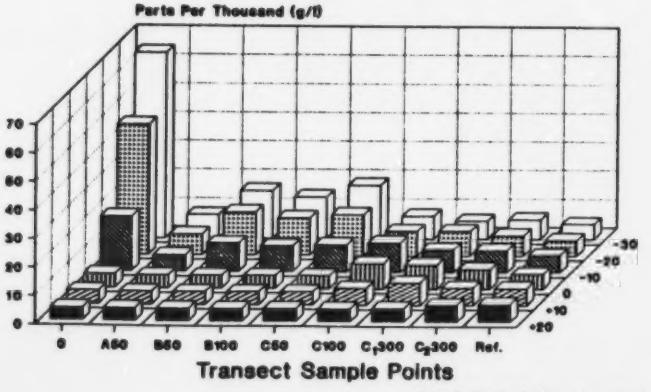
Sample depths (cm) are expressed as above (+) or below (-) the sed/water interface (0).

Fig. 2. Cl Results of Interstitial Water From Sectioned Cores and Overlying Water Strata at all DF Site Stations



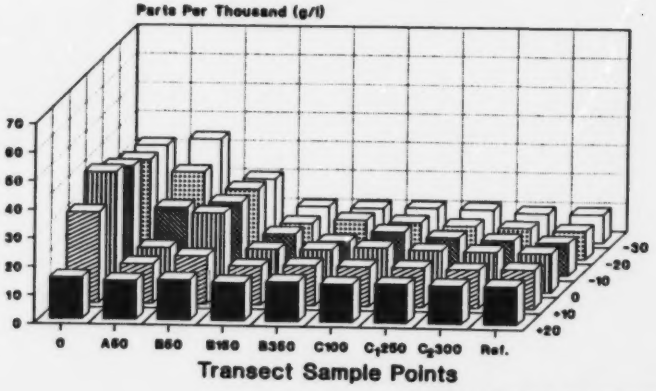
Sample depths (cm) are expressed as above (+) or below (-) the sed/water interface (0).

Fig. 3. Cl Results of Interstitial Water From Sectioned Cores and Overlying Water Strata at all BC Site Stations



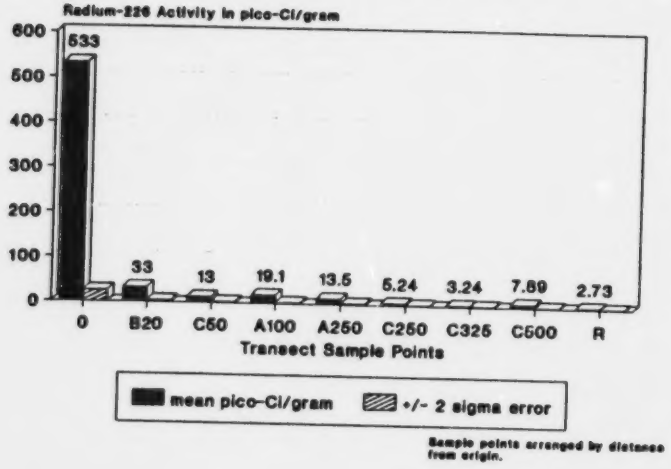
Sample depths (cm) are expressed as above (+) or below (-) the sed/water interface (0).

Fig. 4. Cl Results of Interstitial Water From Sectioned Cores and Overlying Water Strata at all LW Site Stations



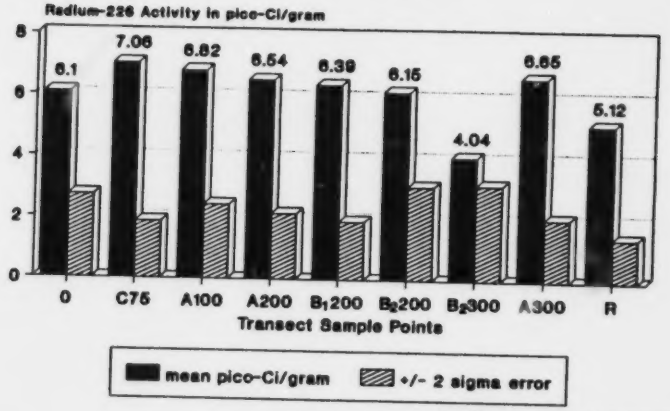
Sample depths (cm) are expressed as above (+) or below (-) the sed/water interface (0).

Figure 5
Lirette Sediment Radium-226 Activities



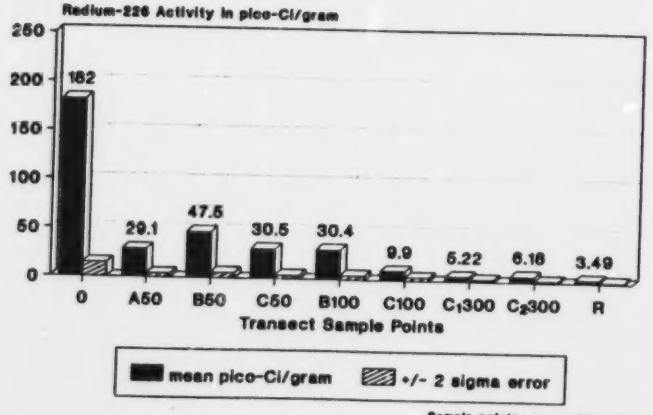
Sample points arranged by distance from origin.

Figure 6
Delta Farms Sediment
Radium-226 Activities



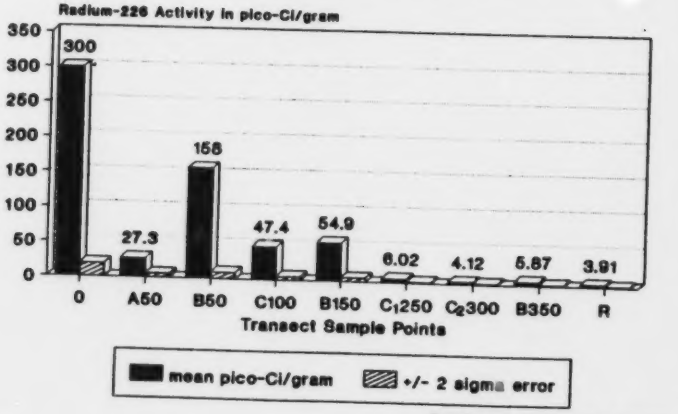
Sample points arranged by distance from origin.

Figure 7
Bully Camp Sediment
Radium-226 Activities



Sample points arranged by distance from origin.

Figure 8
Lake Washington Sediment
Radium-226 Activities



Sample points arranged by distance from origin.

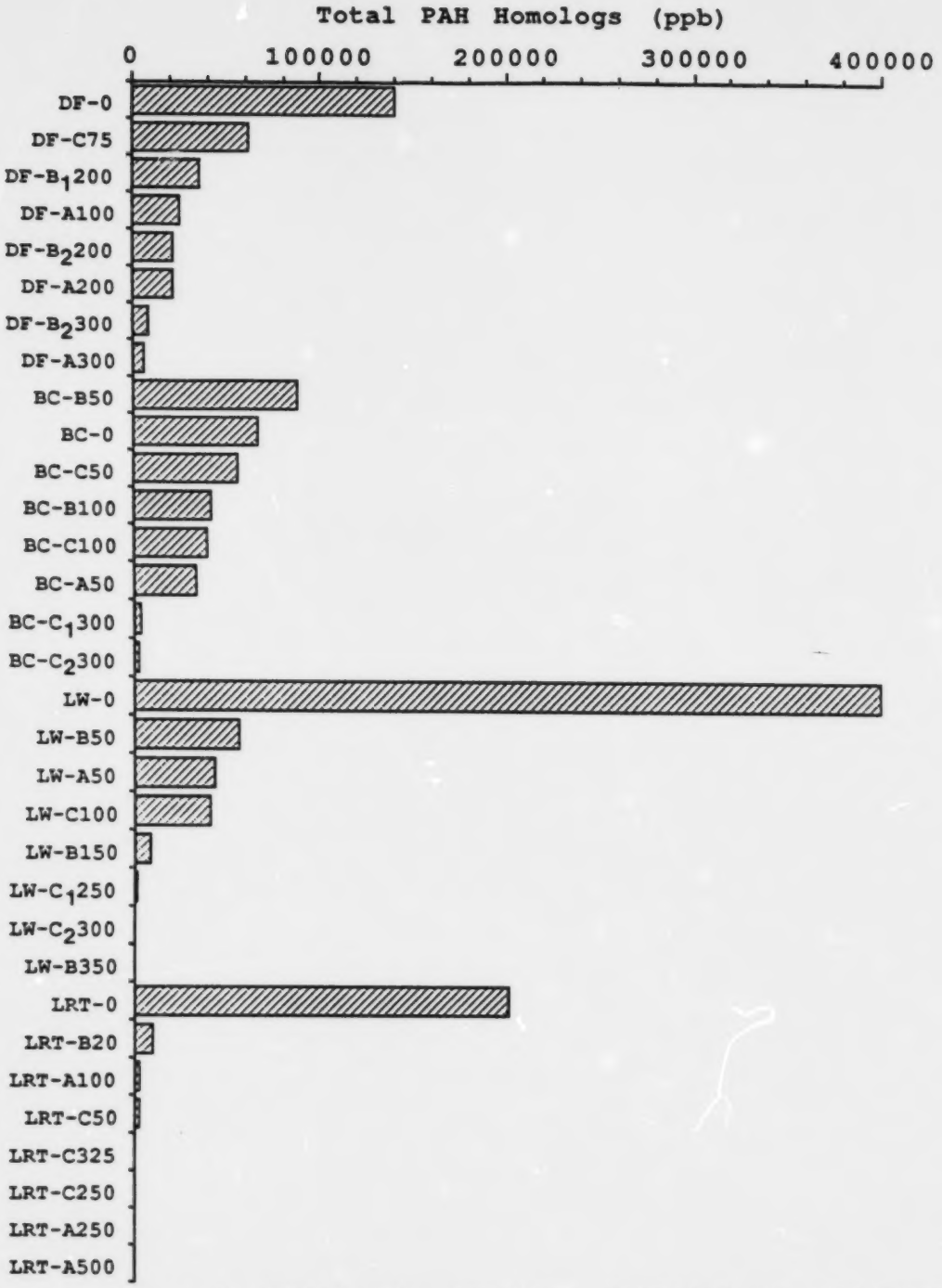


Figure 9. Total PAH homologs detected in sediments in the vicinity of four produced water discharges.

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AN EARLY WARNING SYSTEM TO PREVENT USDW CONTAMINATION

ENVIRONMENTAL UNDERGROUND INJECTION EQUIPMENT FOR HAZARDOUS AND NON-HAZARDOUS LIQUID WASTE DISPOSAL

INJECTION WELL AND MONITORING WELL IN THE SAME BOREHOLE (PHYSICAL PROOF)

W.W. POIMBOEUF, P.E.

ABSTRACT

COMBINATION INJECTION/MONITORING WELL IN A SINGLE BOREHOLE

This paper deals with completion of an injection well for any class well 1, 2, 3 or 5. It deals with the direct monitoring of that injection well from its well bore. This type completion gives positive proof of no contamination of ground water from the injection well. At any time that there is potential danger of ground water contamination, the monitoring system in the injection well shows this potential danger. It shows the danger of contamination in sufficient time so that injection can be stopped and remedial well actions taken so that there will be no contamination. This method of completion gives absolute physical evidence of any possible injection failure long before the injection well could contaminate ground water. The completion is so designed that samples of fluid can be taken from one or more formations above the formation being injected into. As long as these samples show no contamination, it is impossible for the injection well to have a failure. This particular type of completion is especially acceptable to Class I injection wells. Considerable savings can be realized from this type monitoring system in deep wells.

COMPLETING OBSERVATION WELLS AND INJECTION WELLS IN THE SAME WELLBORE

It is possible today to complete an injection well in such a manner that the operator will have proof positive at all times that his injection well is not contaminating fresh water in the vicinity of that well. At the present time injection well integrity is proven by running a series of costly logs initially and the periodic workover of wells, by pulling the injection tubing and again running the costly logs. The process here, as noted, eliminates the need for costly workovers. This procedure allows the operator to continually operate the well without interruption, and at all times knowing that ground water is not being contaminated from it. The need for the costly workover is eliminated, therefore the operator can continually operate these wells for 20 years or more, depending upon the type of completion he selects from the variation herein presented.

There is one basic method shown here, with various ramifications of that method. The basic method is to complete the well as shown in the "Composite Completion Sketch", Figure 24. The package or the casing design is strictly contingent upon the depth to which the well is drilled and the number of strings of 2 3/8" or smaller tubing to be used for monitoring. The size of the injection string of tubing and the various casing strings can be varied. The design depends upon the volume of fluid being injected and the depth of the well, but basically is contingent upon cost and the physical location of the well to be drilled.

The geology used here is very simple. Very complex geology is encountered in some cases. USDW zones sometimes are over 3000 ft. deep. The simple geology is used to more easily explain the completion. Refer to Figure No. 1. At the surface is a permeable zone containing USDW. This is underlain by an impermeable zone which in turn is underlain by a permeable zone. This zone contains salt or fresh water, but contains some fluid. This in turn is underlain by a permeable zone and this in turn is underlain by a permeable zone into which fluid is injected. Zone one is the fresh water zone. Zone two is the first impermeable zone. Zone three is the monitoring zone, and the second permeable zone, Zone four, is an impermeable zone. Zone five is a permeable zone into which the injection will be made. Zone six is an impermeable zone below the zone to be injected into.

The well is started by driving or otherwise setting a string of conductor pipe, Figure 2. It should be set deep enough in the ground to contain unconsolidated sands. Drilling is then accomplished through the conductor pipe to a point into zone #2, Figure 3, at least 100 feet. The surface casing is set at this depth and cemented to the surface. This cases off the fresh water zone in order to protect it. The will is then drilled through zone #3 and seated in zone #4. Monitoring casing is cemented to the surface. The will is then drilled to total depth through the monitoring casing, Figure 4.

A retrievable bridge plug is set in the monitoring casing below the permeable zone #3. A section of monitoring casing is milled out to expose the face of the permeable formation, Figure 5. This milling process is accomplished in a manner such that the face of the formation is cleaned off as much as possible in order that virgin formation fluid can be obtained therefrom. The virgin formation fluid is pumped from this formation by lowering tubing and a pump into the monitoring casing. The fluid is pumped out and an on site chemical analysis is made of this formation fluid. These are merely basic chemical analyses to determine the chemistry of the virgin fluid. With the virgin fluid in the wellbore, the retrievable bridge plug is removed.

The completion string of injection casing is then run in the hold, it will consist of a cement guide shoe, injection casing up to a point below the exposed formation, a cement retaining element, it is a mistake to call these packers, when they are actually cement retainers. The cement retainer or packer is designed to have three connections, top and bottom for 2 3/8" tubing and injection casing, Figure 15. Both of the 2 3/8" tubing sections are installed, one is perforated and one non-perforated tubing. Injection casing is also installed. Approximately 60 feet above the top of the lower packer a second packer is installed. Monitoring tubing and injection casing will be run to the surface. The other 2 3/8" tubing opening will be left as is, Figure 6. This is the channel for cement to follow when cementing in the injection casing.

When the injection casing has been landed, setting of the two packers will be initiated. The selected packer here is hydraulically set, the packer can also be cup type or other. The packer is set by pressuring the injection casing, therefore, hydraulically extruding the sealing elements of the packer against the monitoring casing, Figures 14 and 15.

This straddle type arrangement isolates the monitoring formation from the surface and from the injection zone, Figure 13.

At this point, normal cementing procedures can be used in the injection casing and the 2 3/8" monitoring string. Cement is pumped through the injection casing inside down through the guide shoe, up around the outside of the injection casing until it reaches the bottom of the lower packer. At this point it follows a path up through the 2 3/8" tubing string to the top of the upper packer, then it follows a path upward around the monitoring tubing string and the injection casing string to the surface. Centralizers are used to ensure that there is coverage of the monitoring tubing and injection casing, Figures 7, 13, 14 and 15.

At this point the well is perforated in the injection zone. Another variation for this type injection well is an open hole completion.

All drilling should be accomplished with fresh water in order that none of the permeable formations will be contaminated with drilling fluid. There is no need for expensive drilling fluid, since we do not anticipate any pressure problems in the well.

The injection tubing string with a packer on the bottom is now run in the hold. The packer is set and the tubing is landed in the wellhead assembly Figures 17 and 19. The type tubing to be used and the type packer to be used will be based upon the type fluid to be injected. If one uses a corrosive fluid for injection, he should consider using fiberglass tubing and an internal coated packer, Figure 8.

The wellhead assembly is now in place. It is necessary to button up the well, we do this by tightening down on the stud bolts through the rubberized packing elements. Tightening these bolts will seal off the casing tubing annulus and seal off the injection casing. There can be variations in this type wellhead assembly equipment. These variations depend on the type completion, Figure 9. The casing tubing annulus is filled with fluid to enable monitoring for leaks, Figure 10.

There is an opening to the tubing casing annulus. This is connected to a monitoring pot, Figure 18. The monitoring pot is a vessel constructed such that a fluid level in the pot will give a positive indication of a tubing/casing annulus leak. Pressure is applied (50 to 100 psi) on the monitoring pot. The level of fluid in the monitoring pot can be observed in the sight-glass on the side of the pot. As long as the fluid is in the monitoring pot, there is no leakage in the injection casing or the injection tubing annulus, Figure 10.

Injection through the tubing can now safely be done, Figure 11.

There are many variations to this type completion. These are contingent upon the depths and fluids being injected. One variation that should be strongly considered is that by which the injection casing string and monitoring string are not cemented to the surface, Figure 23. They are cemented approximately to 100 feet above the upper-most packer. This will leave a second annulus which can be monitored. This monitoring pot can be connected to this annulus and it monitored in the same manner as the tubing casing annulus. As long as there is no pressure change or loss of fluid from the injection/monitoring annulus, there cannot be any loss of fluid through the injection casing wall.

It is possible also to place two or even three or even possibly four monitoring strings of tubing in the annulus between the injection casing and the monitoring casing. Each monitored formation would need be isolated with a straddle packer arrangement as is shown in the simple completion, Figures 16, 20 and 23.

The costs and savings of this type completion is of importance. Attached is a cost of a simple type completion. In the simple case, the difference in cost will be that of an additional string of casing, two packers, milling, three days rig time, 2,000 feet of 2 3/8" tubing, tool rental, logs and service.

At the end of five years, the cost of a "Present Day" completion method is $226,000. The cost of the Poimboeuf method is $203,000. After ten years, the cost of th "Present Day Method" is $276,000; in fifteen years, $326,000. The Poimboeuf method is a one time cost, Figure 25.

There is a risk of even a higher cost in a "Present Day Method." The costs above are based on trouble free well workover. Well workover is normally not trouble free. When one is working underground many unforeseen minor details can become major costs. A $50,000 workover can easily become a $100,000 workover, one in twenty workovers go wrong and cost more. One in forty to fifty wells are lost due to unforeseen problems during workover. This added risk is not necessary in the Poimboeuf method.

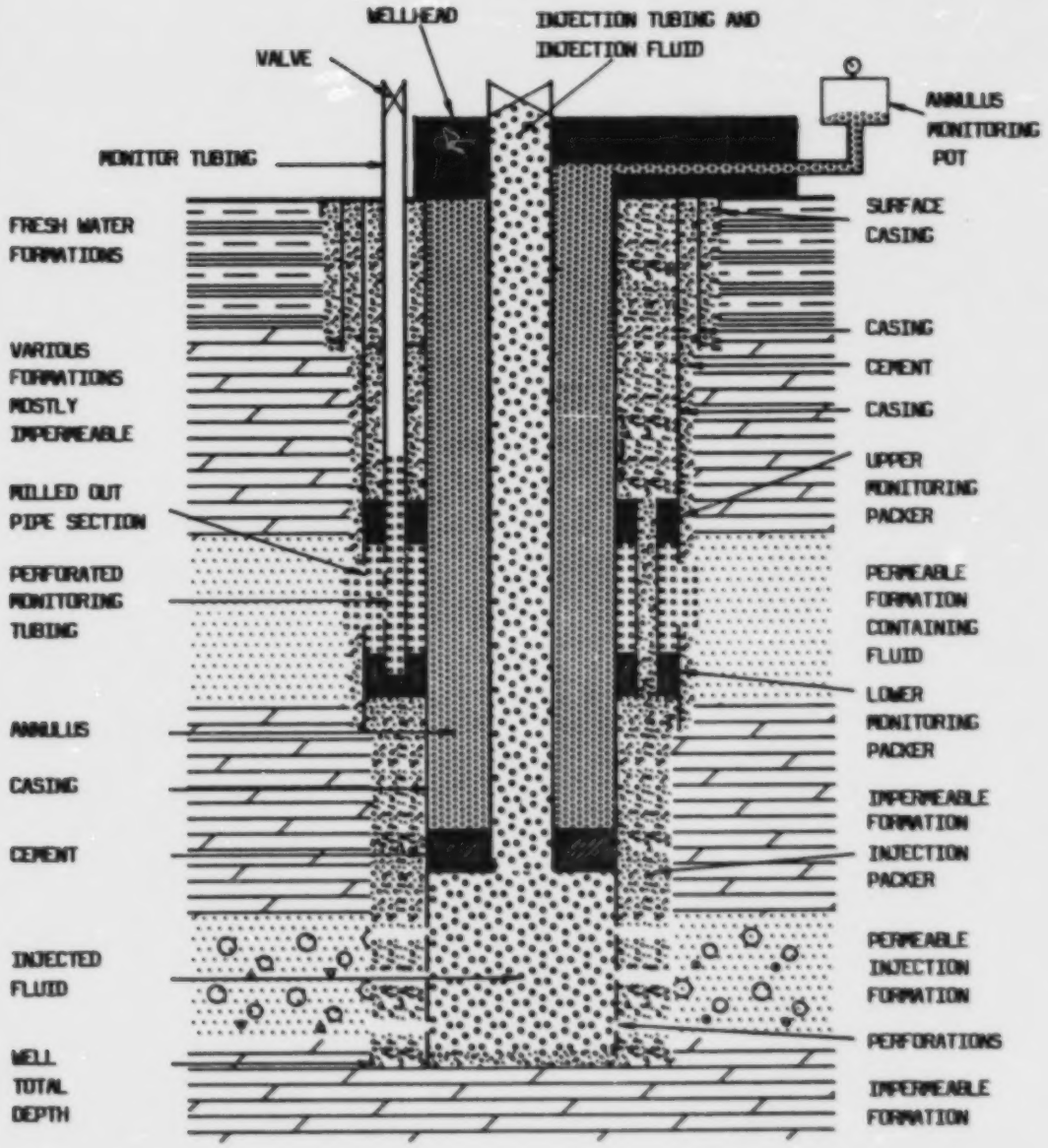
The completion has been discussed with various state regulatory bodies and with individuals in the Federal EPA. The Federal EPA have not turned it down nor have they actually accepted it. Three state regulatory bodies were contacted and copies of the procedure given them. In all three cases, these regulatory bodies stated that they felt the procedure was good and that they would approve this type procedure for an injection well. On extremely shallow injection wells, it is probably less expensive to drill a separate monitoring well near the injection well. There is no assurance that the monitoring well will not have vertical fluid communication upward, around the outside of the monitoring string casing. Improper grouting, and in many cases no grouting, results in this type external communication. This possiblity is eliminated in the case being presented here.

There are many variations of completion equipment. Any type cement retainer (packer) which will satisfactorily straddle the monitored formation will be acceptable for cementing. Probably the lease expensive is a short section of injection casing and two short sections of tubing and rubber cups imbedded in plastic or fiberglass. The purpose of this packer is merely to hold cement in position until it hardens. Fiberglass casing and tubing is available for this type completion. Fiberglass packers can easily be built. These give a better seal against leaks and eliminate corrosion.

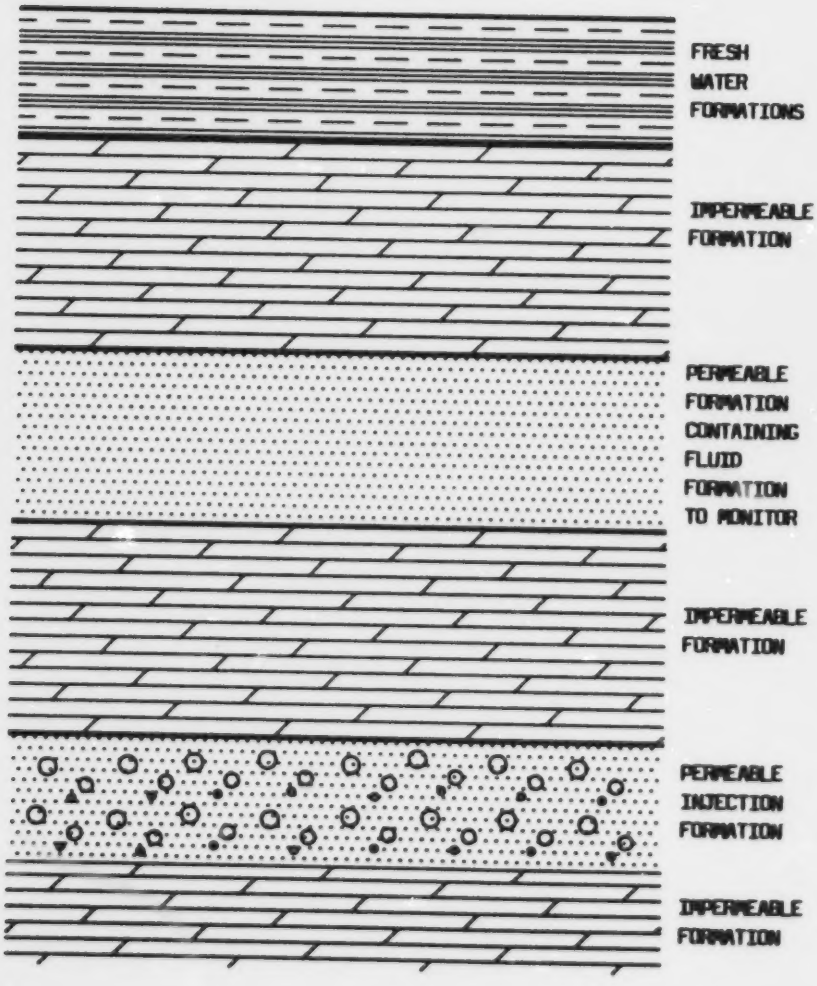
Should one desire to monitor more than one formation in the borehold, it can be done by adding straddle packers and monitoring tubing for each monitored formation.

This method gives physical proof of no contamination of USDW. One cannot argue with physical proof. All "Present Day" methods are theoretical.

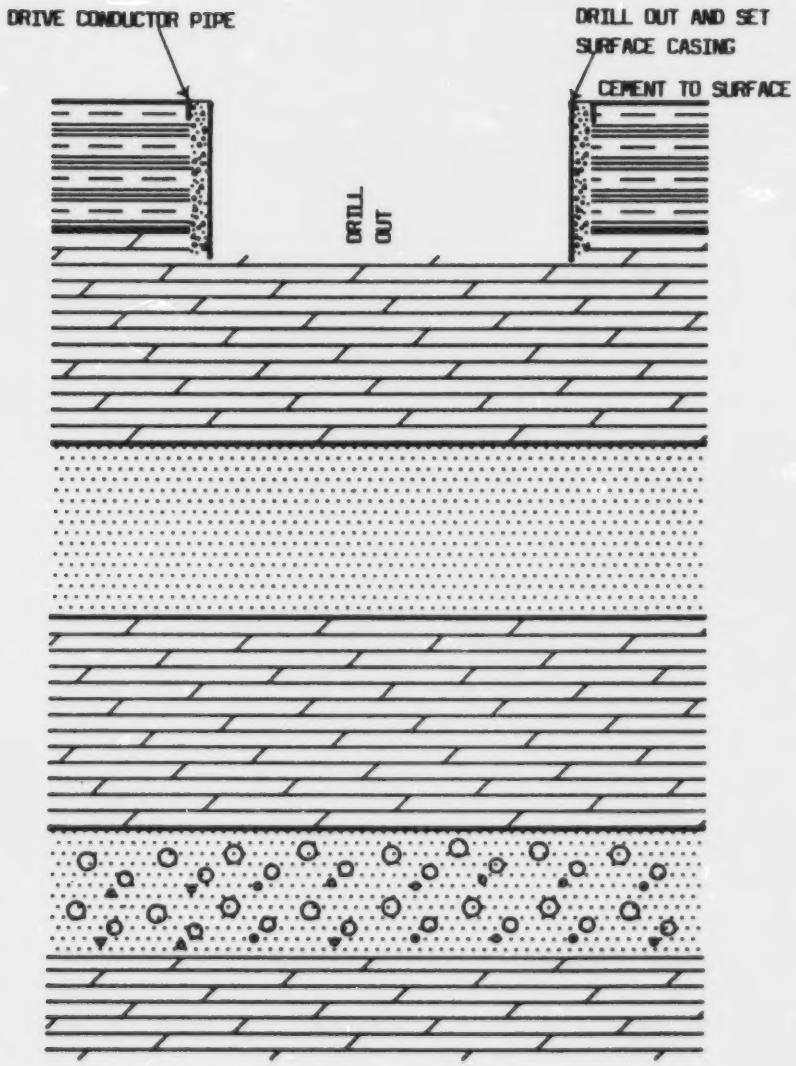
COMPOSIT
INJECTION WELL WITH MONITORING SYSTEM INSTALLED
SAMPLE - SIZES VARY - SCHEMATIC
(POIMBOEUF - BUCK METHOD)
FIGURE NO. 1



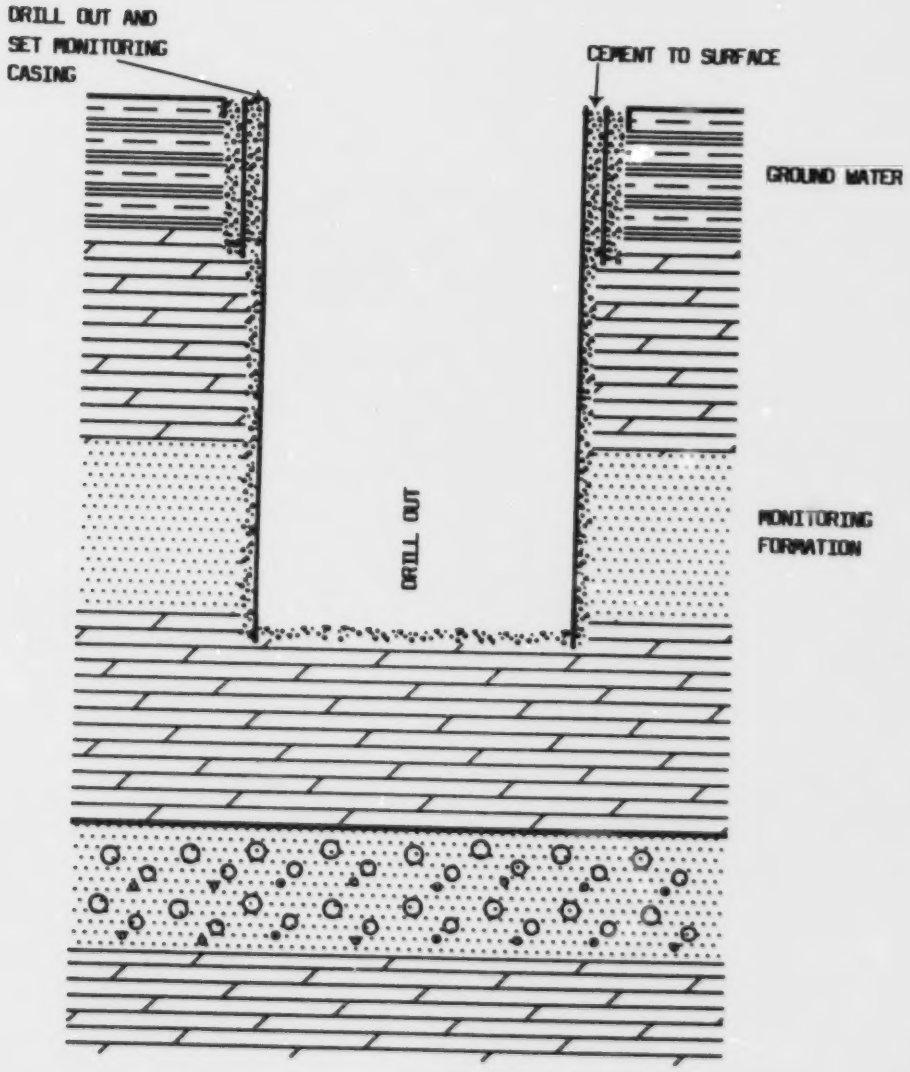
GEOLOGY FOR INJECTION
AND MONITORING
FIGURE NO. 2



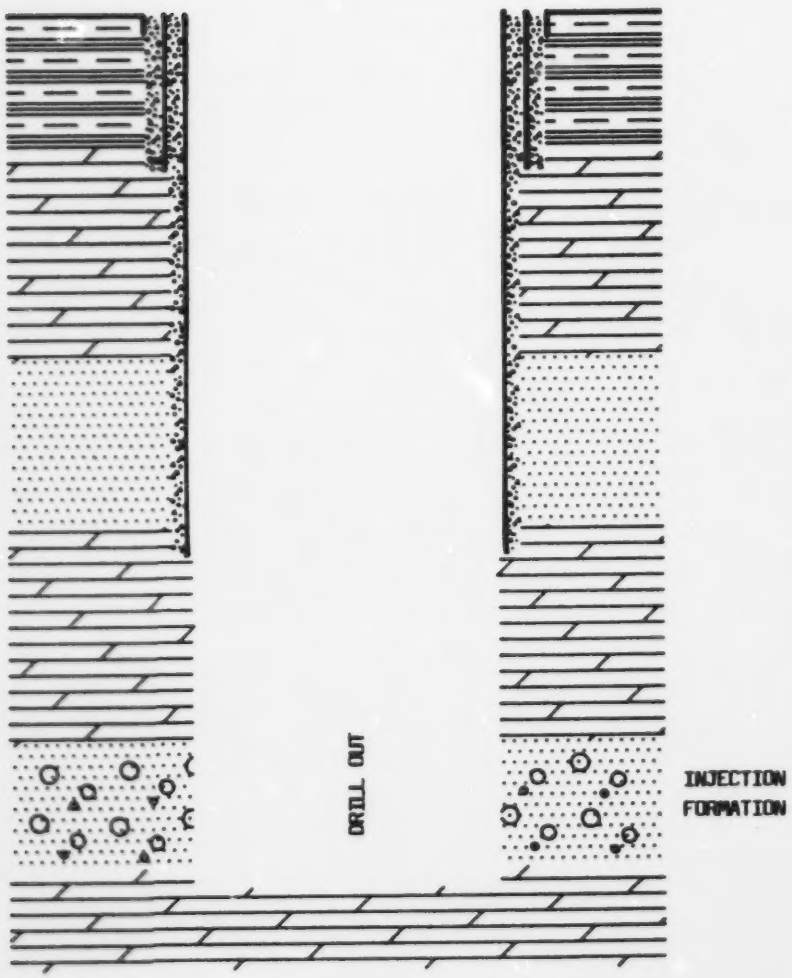
STEP NO. 1
INJECTION/MONITORING WELL
FIGURE NO. 3



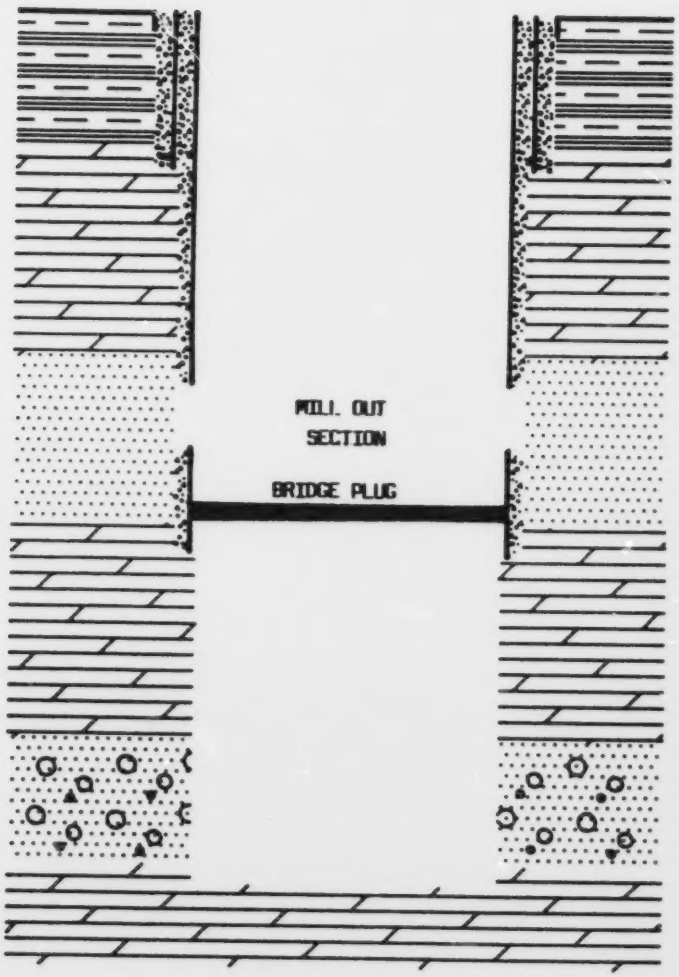
STEP NO. 2
MONITORING CASING THRU
MONITORING FORMATION
FIGURE NO. 4



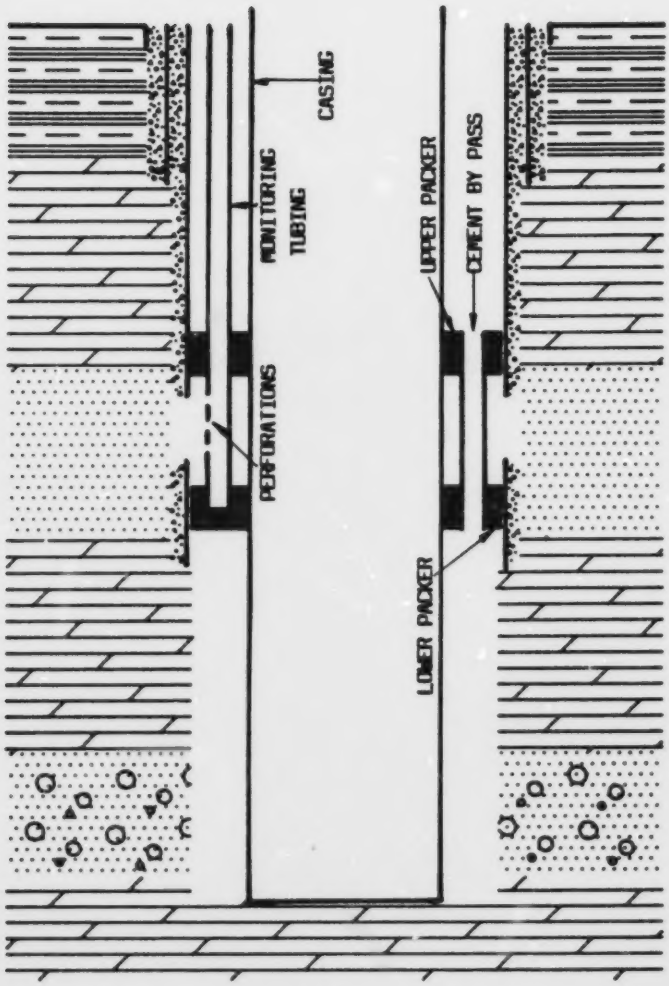
STEP NO. 3
DRILL OUT FOR INJECTION CASING
DRILL THRU INJECTION ZONE
FIGURE NO. 5



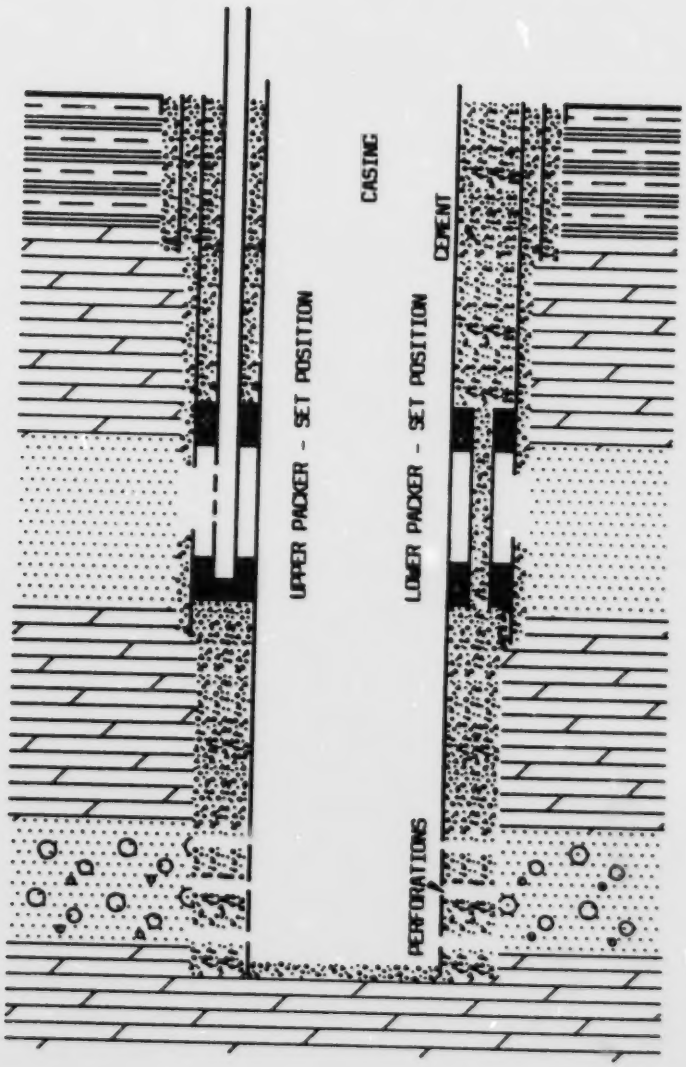
STEP NO. 4
EXPOSE MONITORING FORMATION
BY MILLING OUT SECTION OF 16"
MONITORING CASING AND CEMENT
FIGURE NO. 6



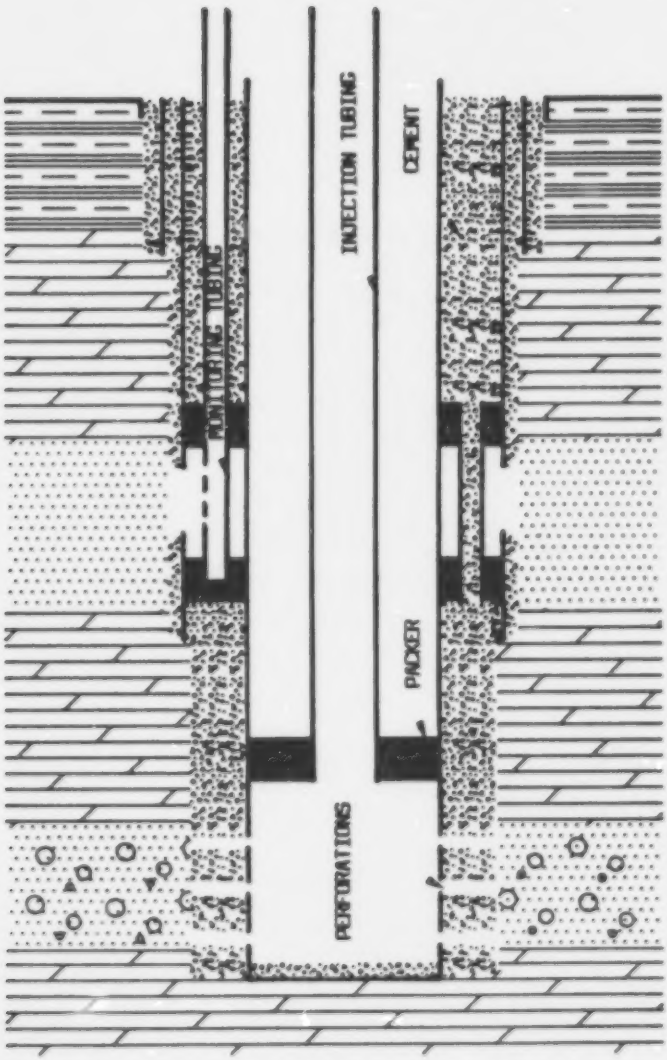
STEP NO. 5
RUN INJECTION CASING STRING CONSISTING
OF CASING, STRADDLE PACKERS SYSTEM,
MONITORING TUBING (PERFORATED), CEMENT BYPASS
FIGURE NO. 7



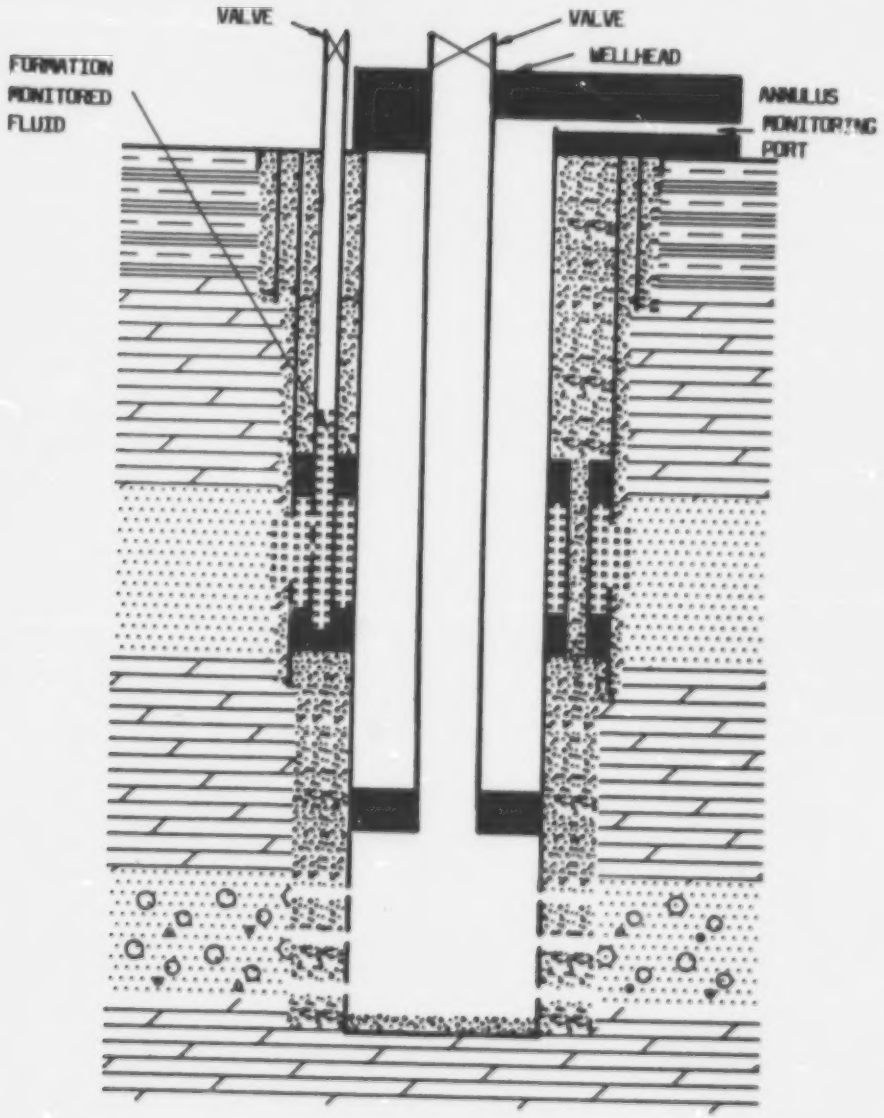
STEP NO. 6
RUN INJECTION CASING STRING CONSISTING
OF CASING, STRADDLE PACKERS
SYSTEM, MONITORING TUBING, CEMENT BY PASS,
CEMENT TO SURFACE
FIGURE NO. 8



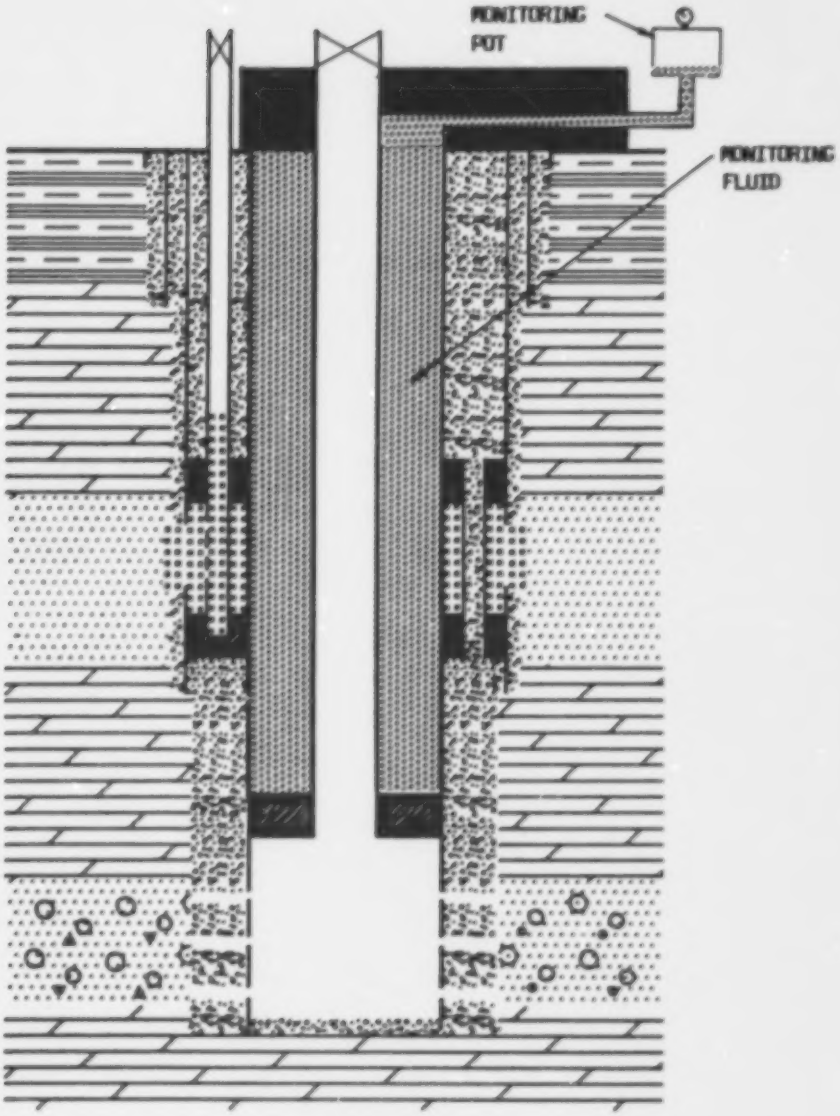
STEP NO. 7
CONNECT MONITORING TUBING
RUN INJECTION TUBING WITH PACKER
FIGURE NO. 9



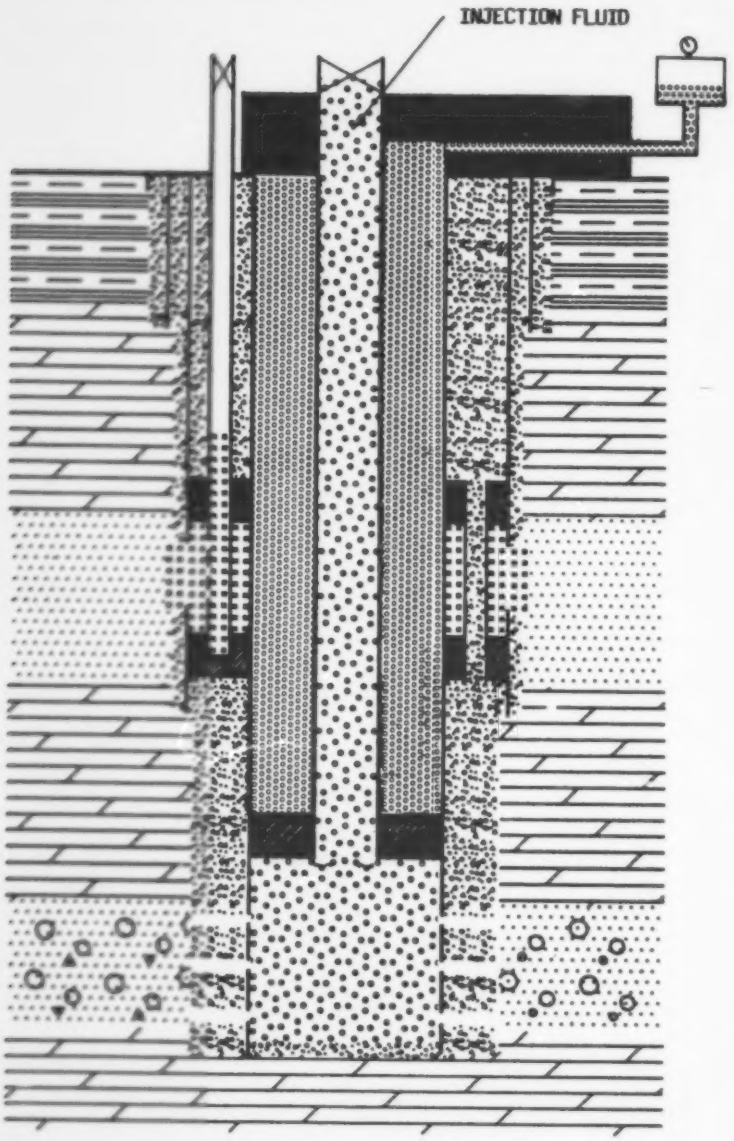
STEP NO. 8
INSTALL WELLHEAD
FIGURE NO. 10



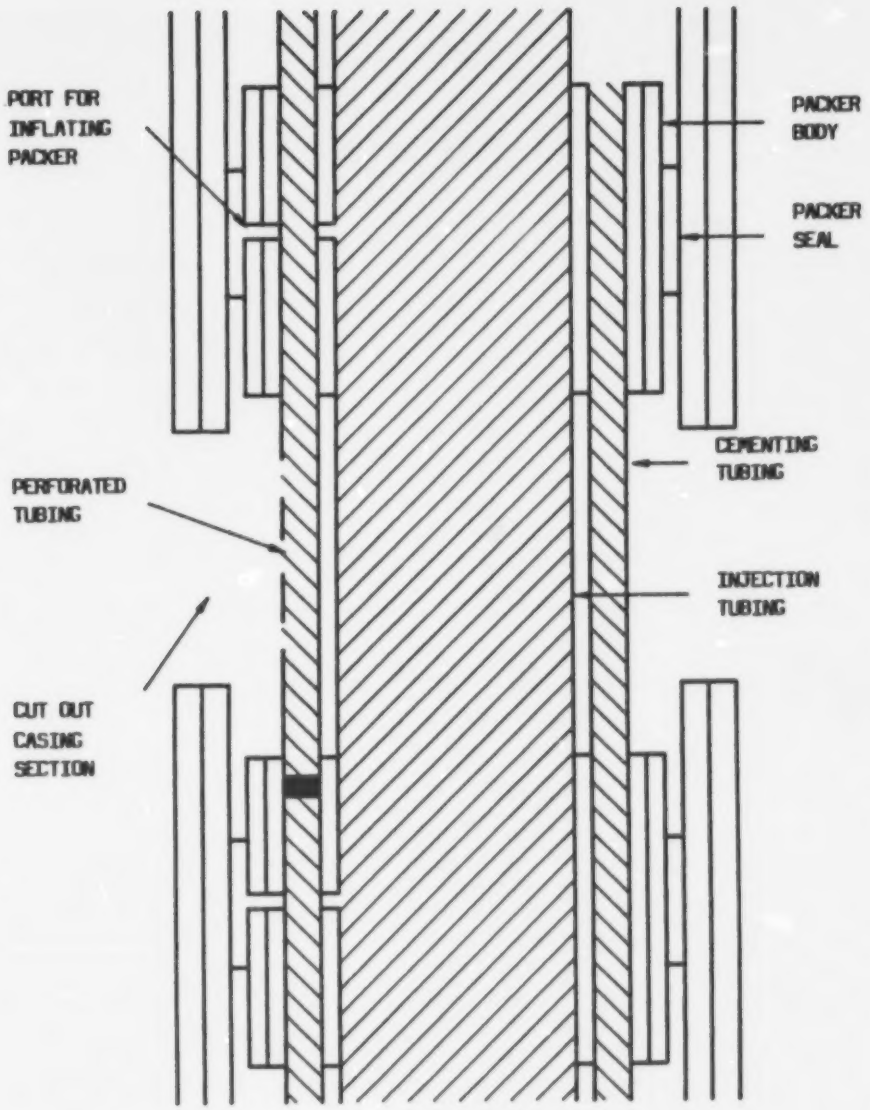
STEP NO. 9
INSTALL ANNULUS MONITORING FLUID
AND ANNULUS MONITORING POT
FIGURE NO. 11



STEP NO. 10
BEGIN INJECTION
FIGURE NO. 12



EXPANDED PACKER ARRANGEMENT
FIGURE NO. 13



CUP TYPE PACKERS ARRANGEMENT
FIGURE NO. 14

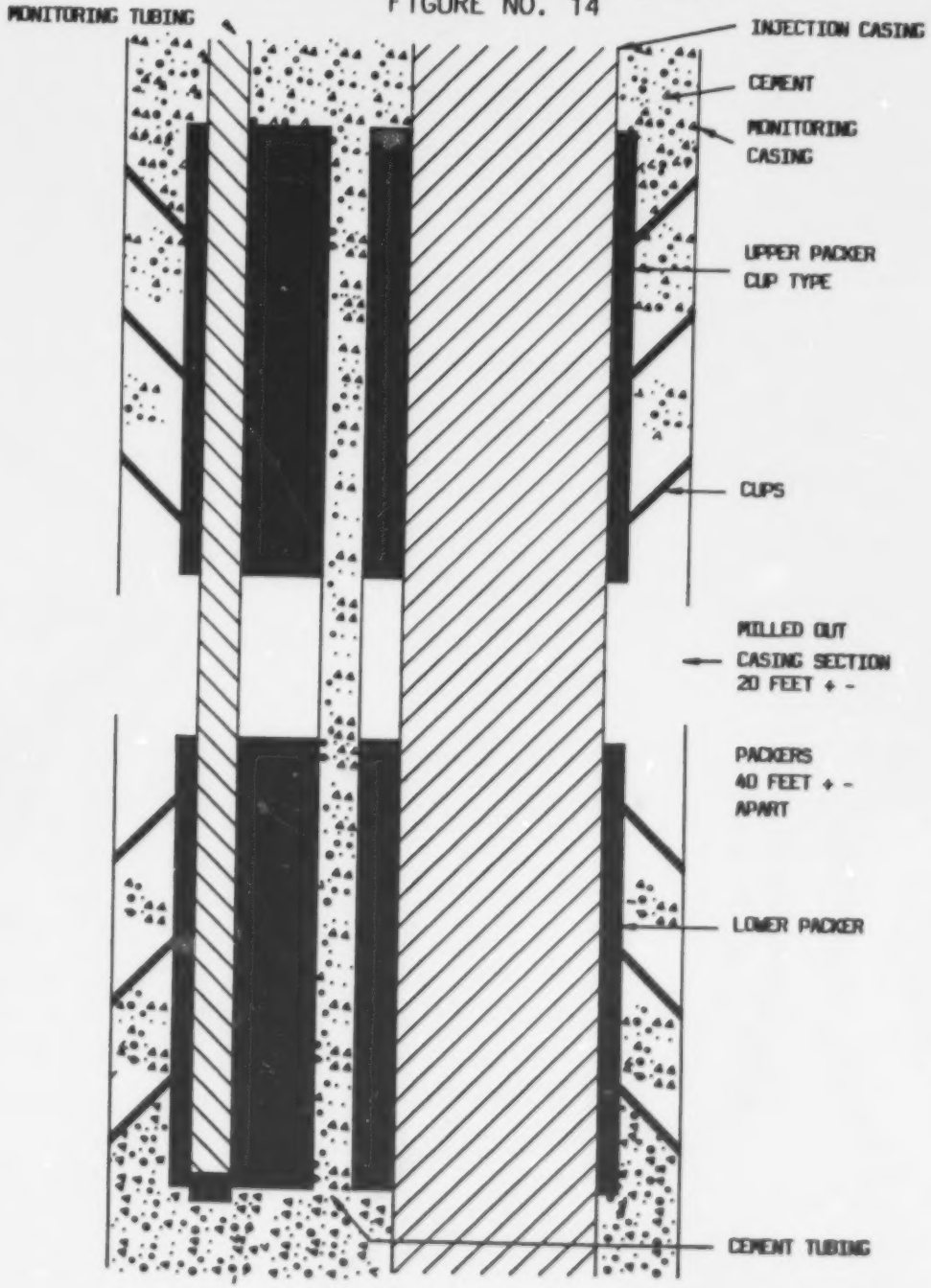
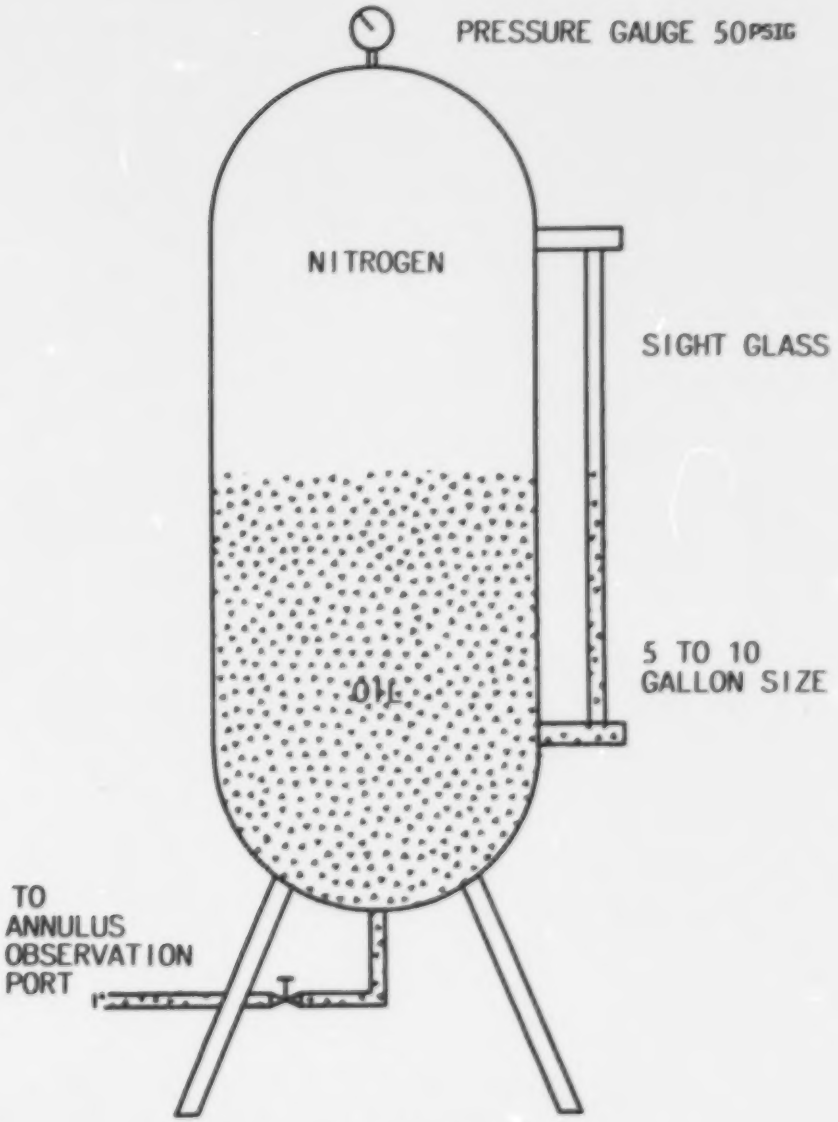
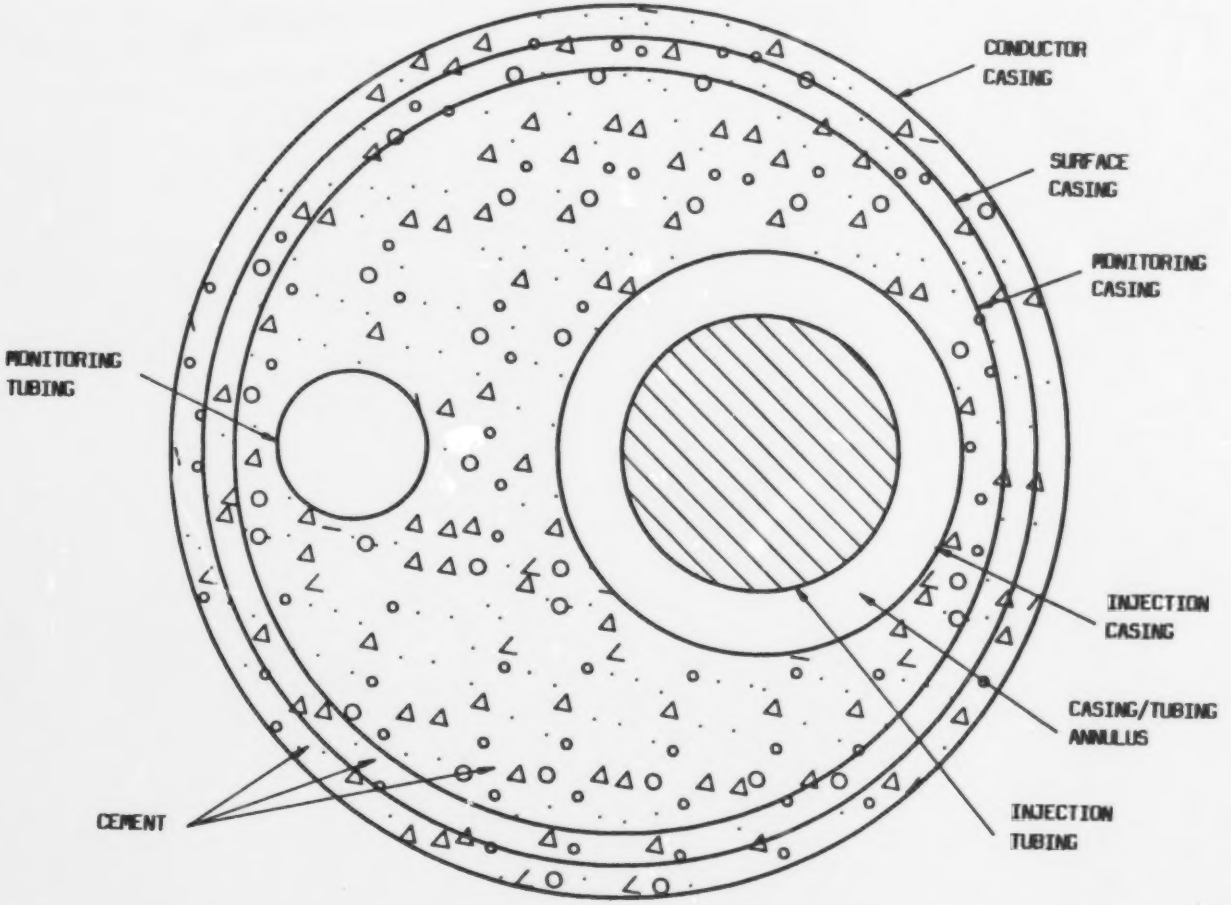


FIGURE NO. 15

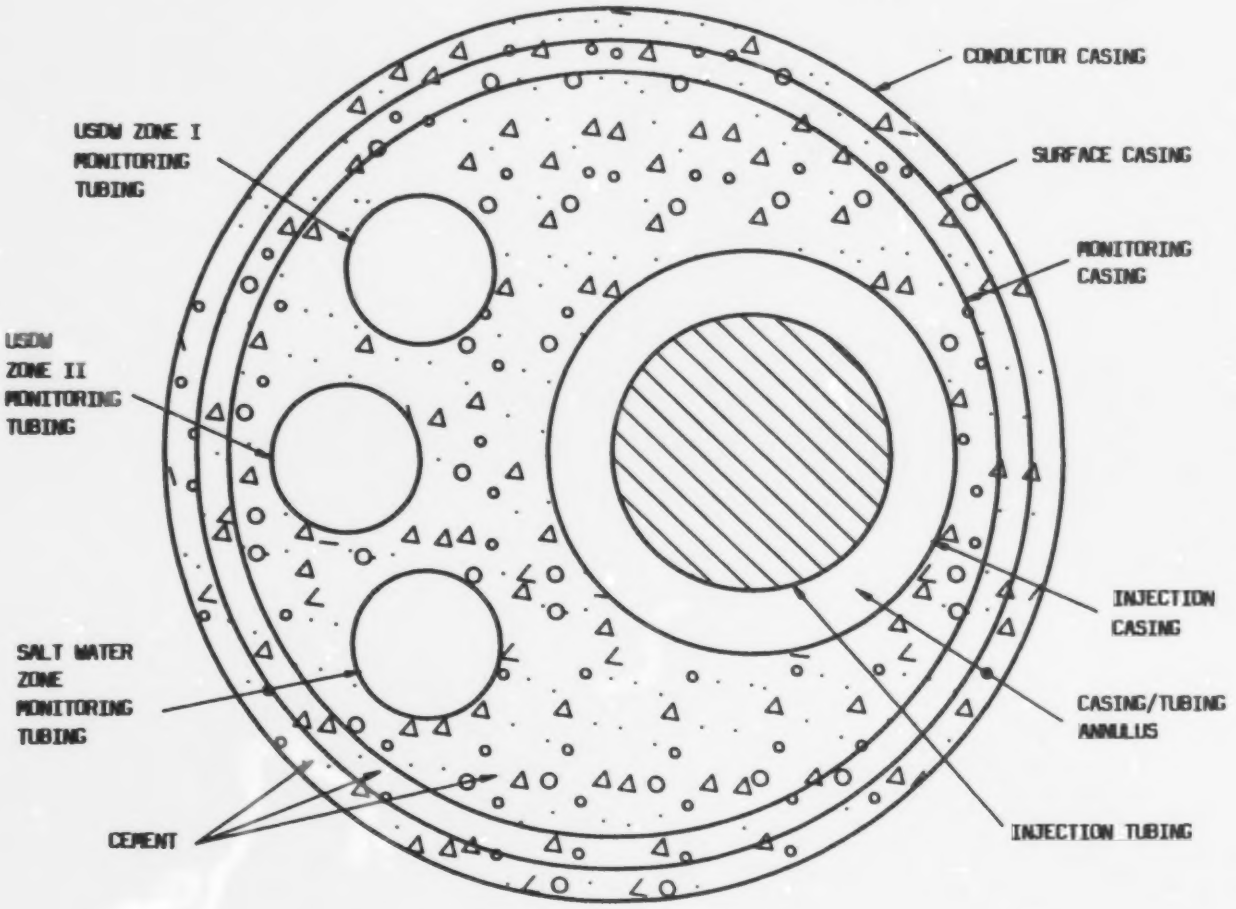


ANNULUS MONITORING POT

CROSS SECTION THRU GROUND LEVEL CASING ARRANGEMENT - CASE I
FIGURE NO. 16



CROSS SECTION THRU GROUND LEVEL CASING ARRANGEMENT
MULTIPLE ZONE MONITORING
FIGURE NO. 17



CROSS SECTION THRU PACKER
EXAMPLE SHOWN

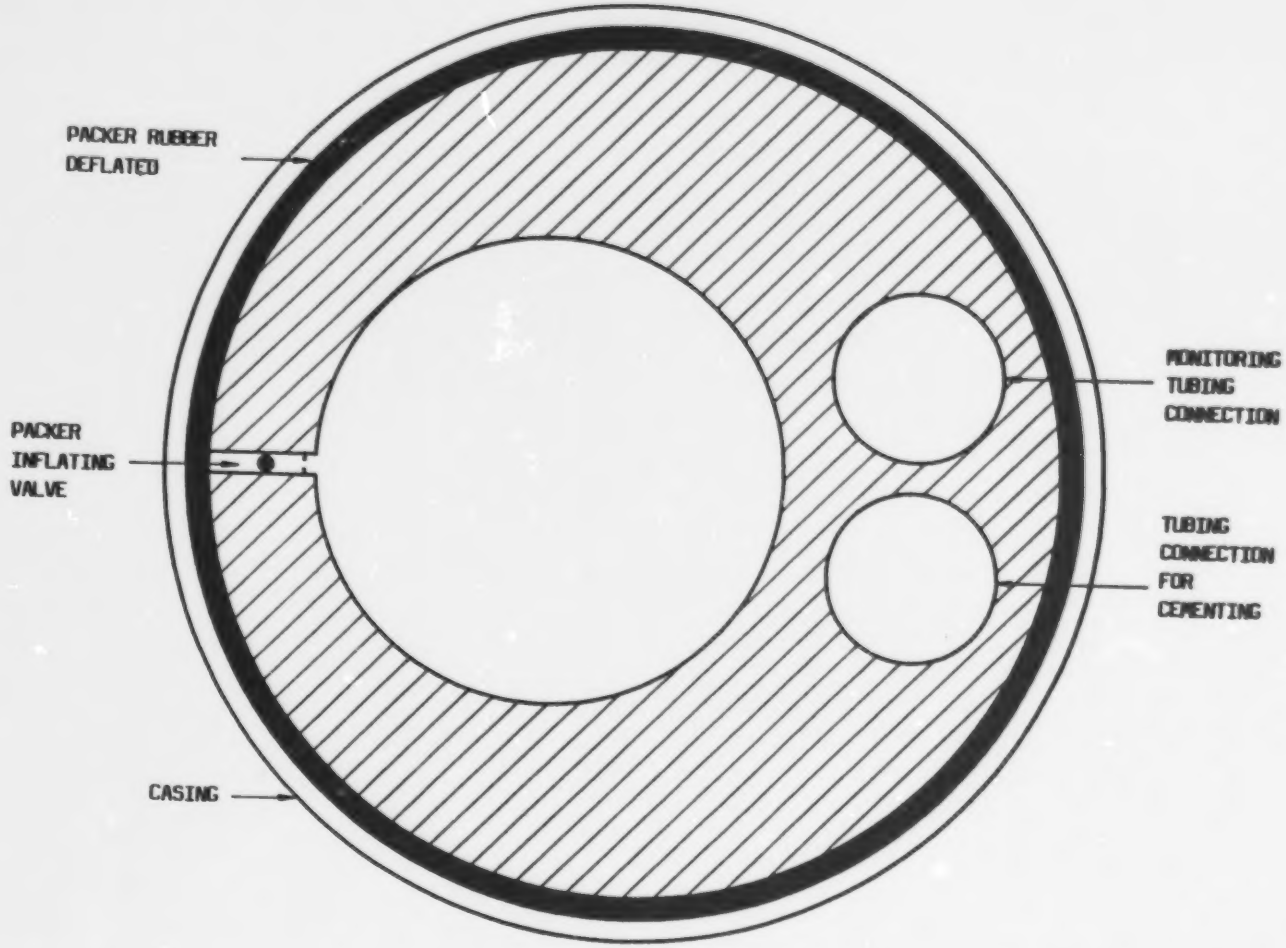


FIGURE NO. 18

PACKER CROSS SECTION FOR MONITORING
THREE SEPARATE ZONES

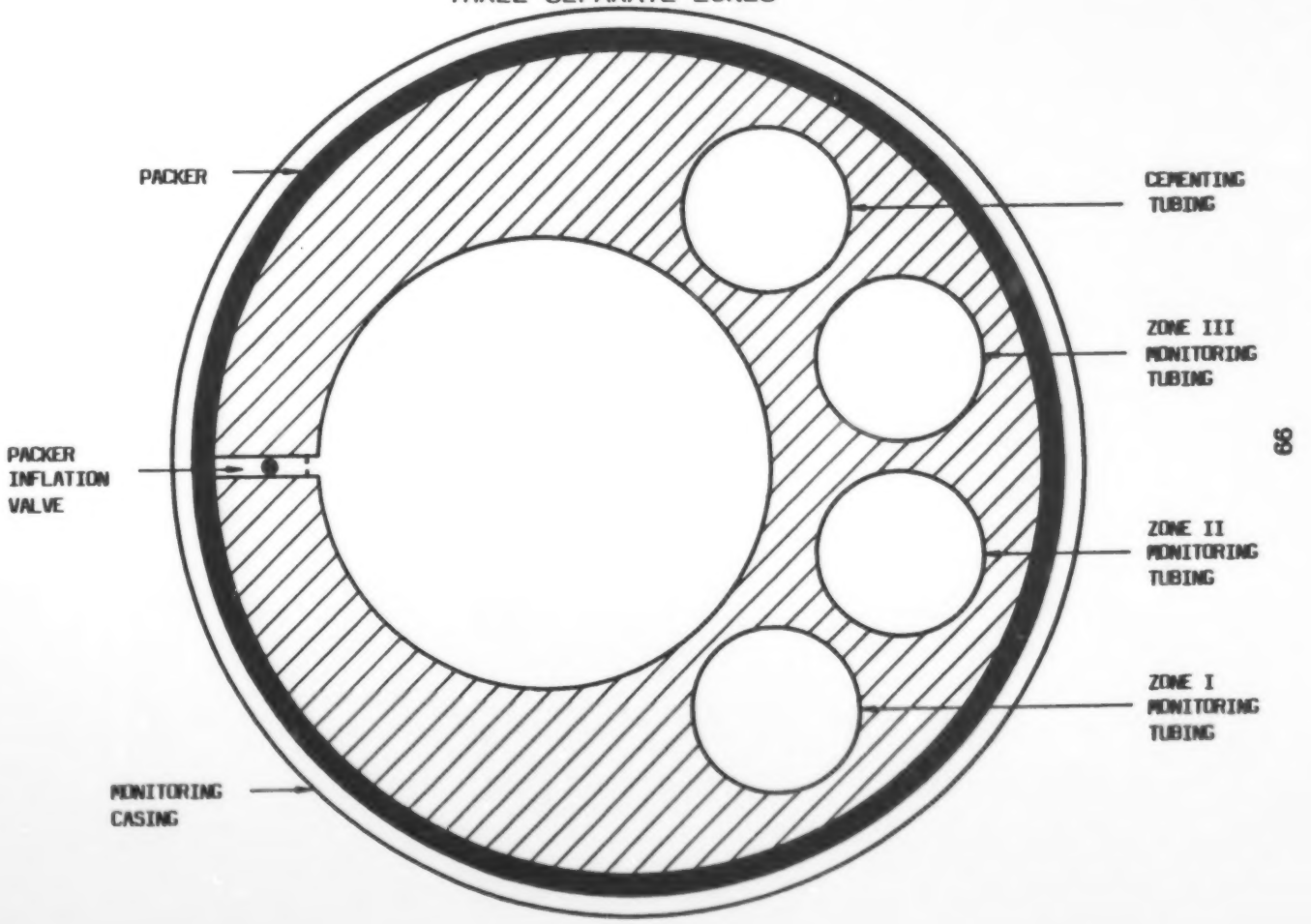
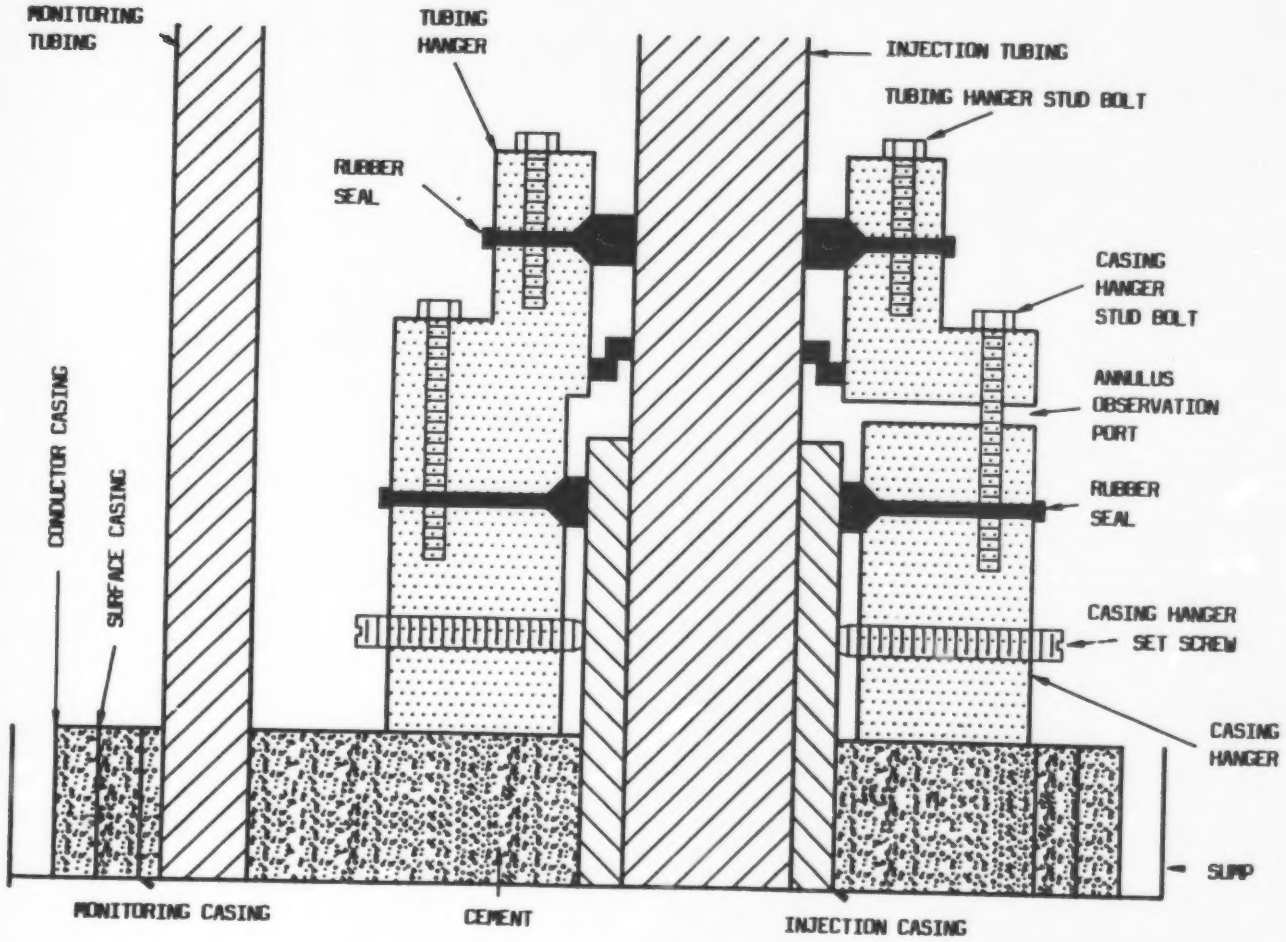
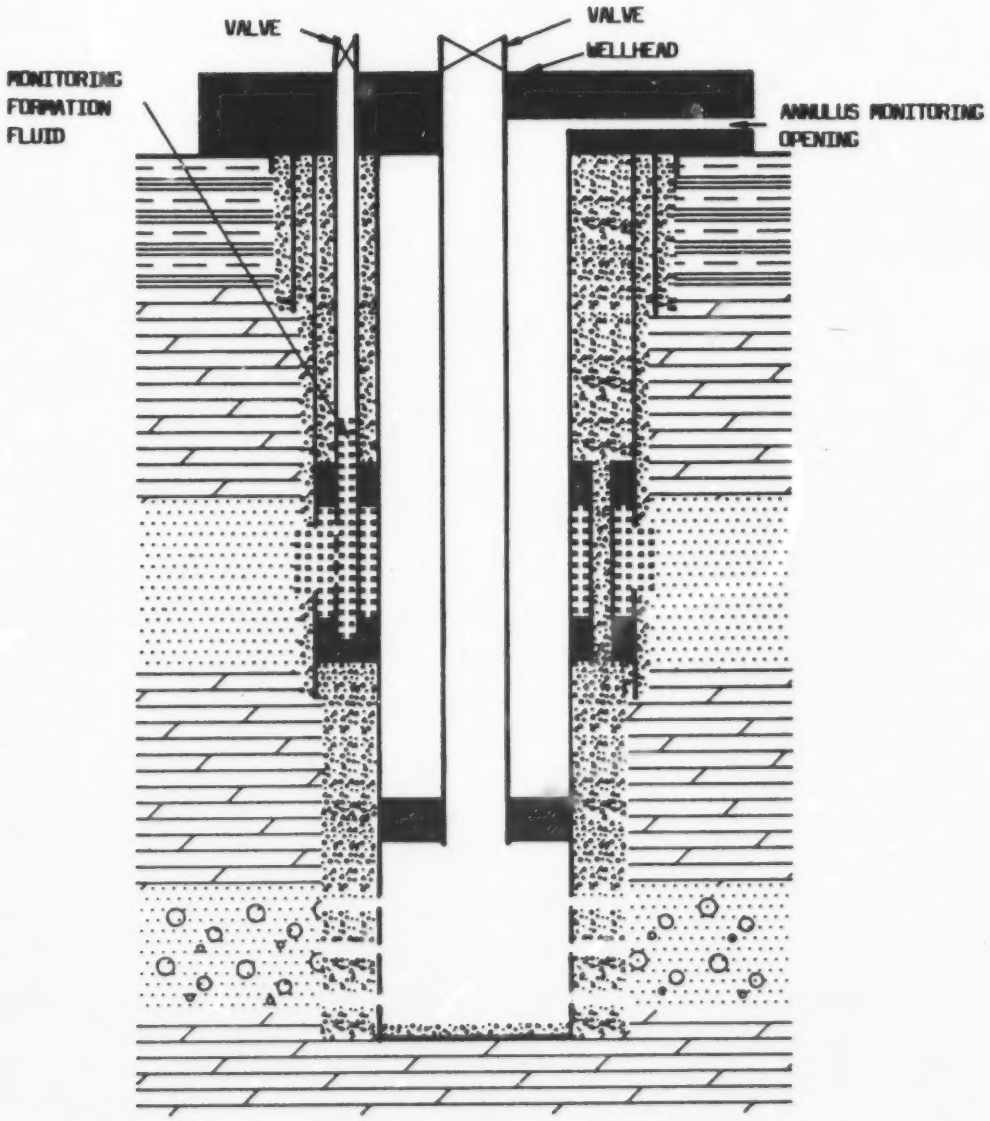


FIGURE NO. 19

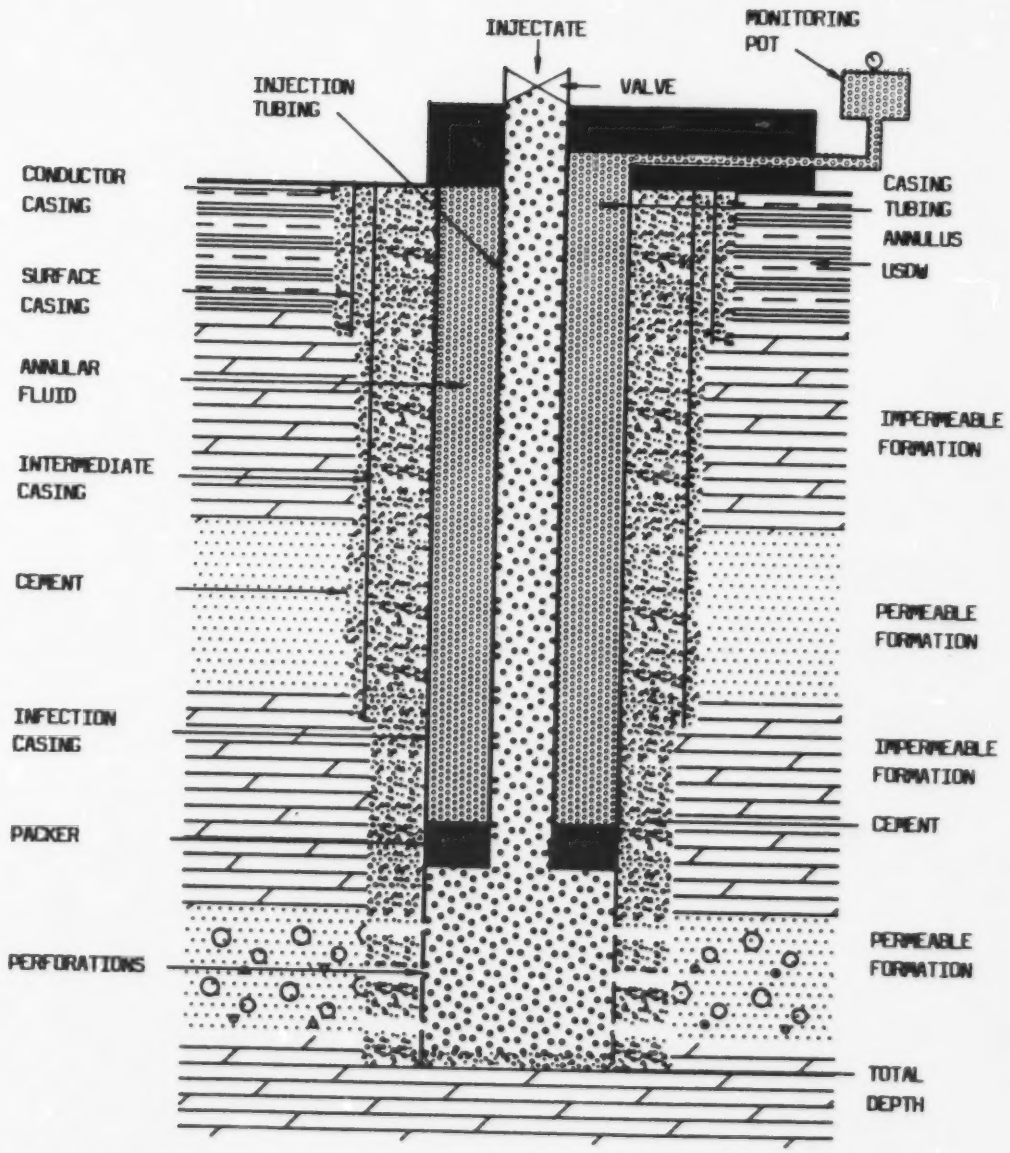
WELLHEAD EQUIPMENT EXPANDED
SCHEMATIC - VERTICAL SECTION - CASE I
FIGURE NO. 20



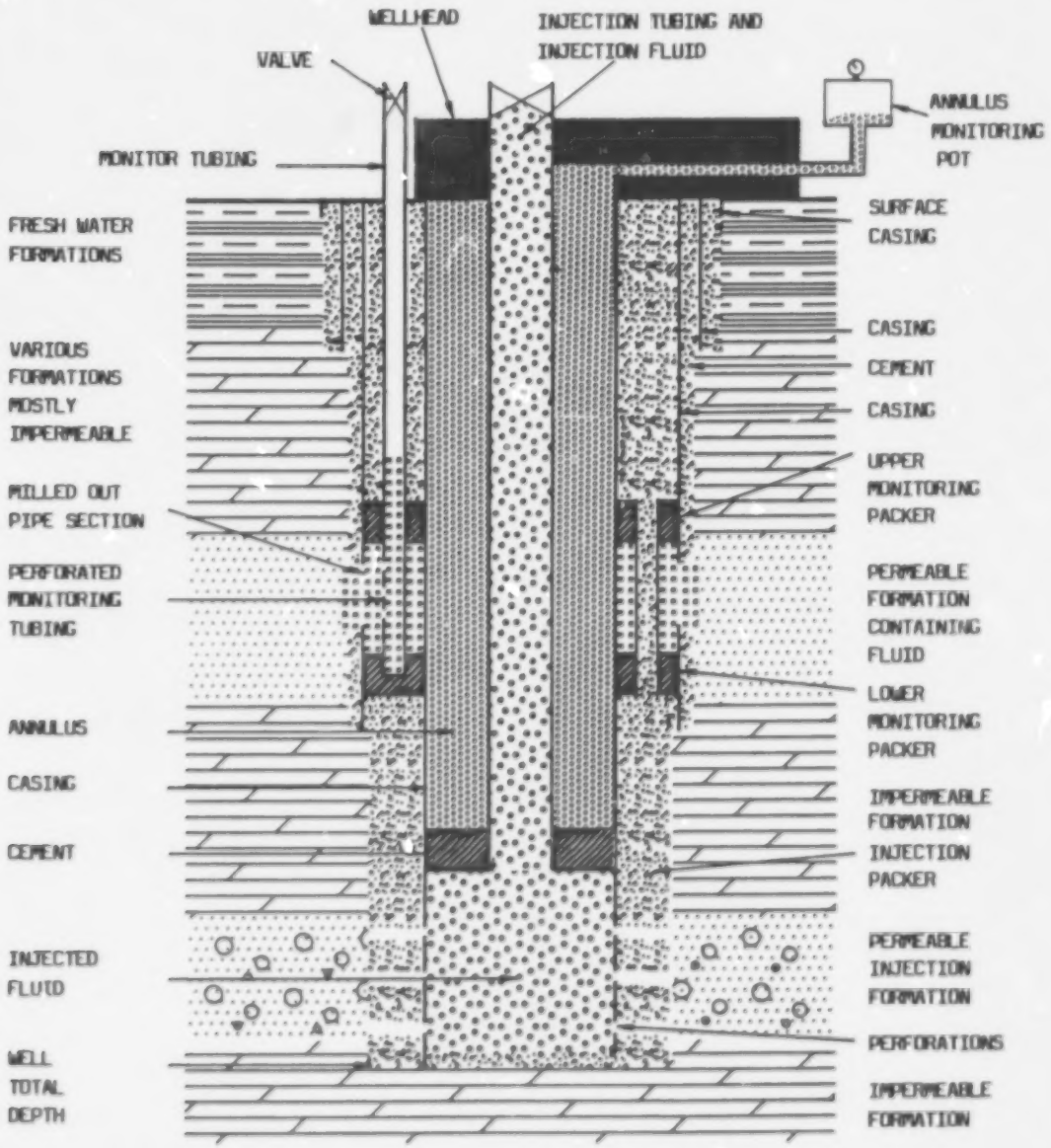
STEP NO.
INSTALL WELLHEAD EQUIPMENT
FIGURE NO. 21



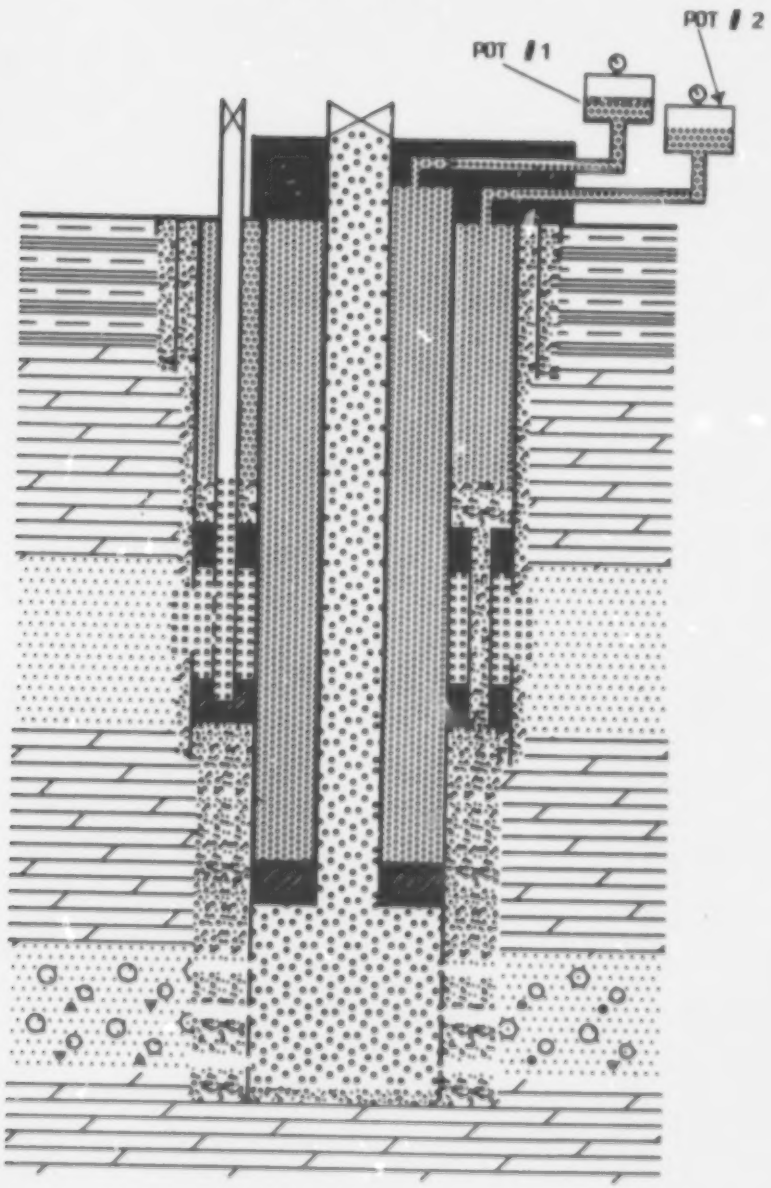
PRESENT DAY COMPLETION
CLASS I OR II WELL
FIGURE NO. 22



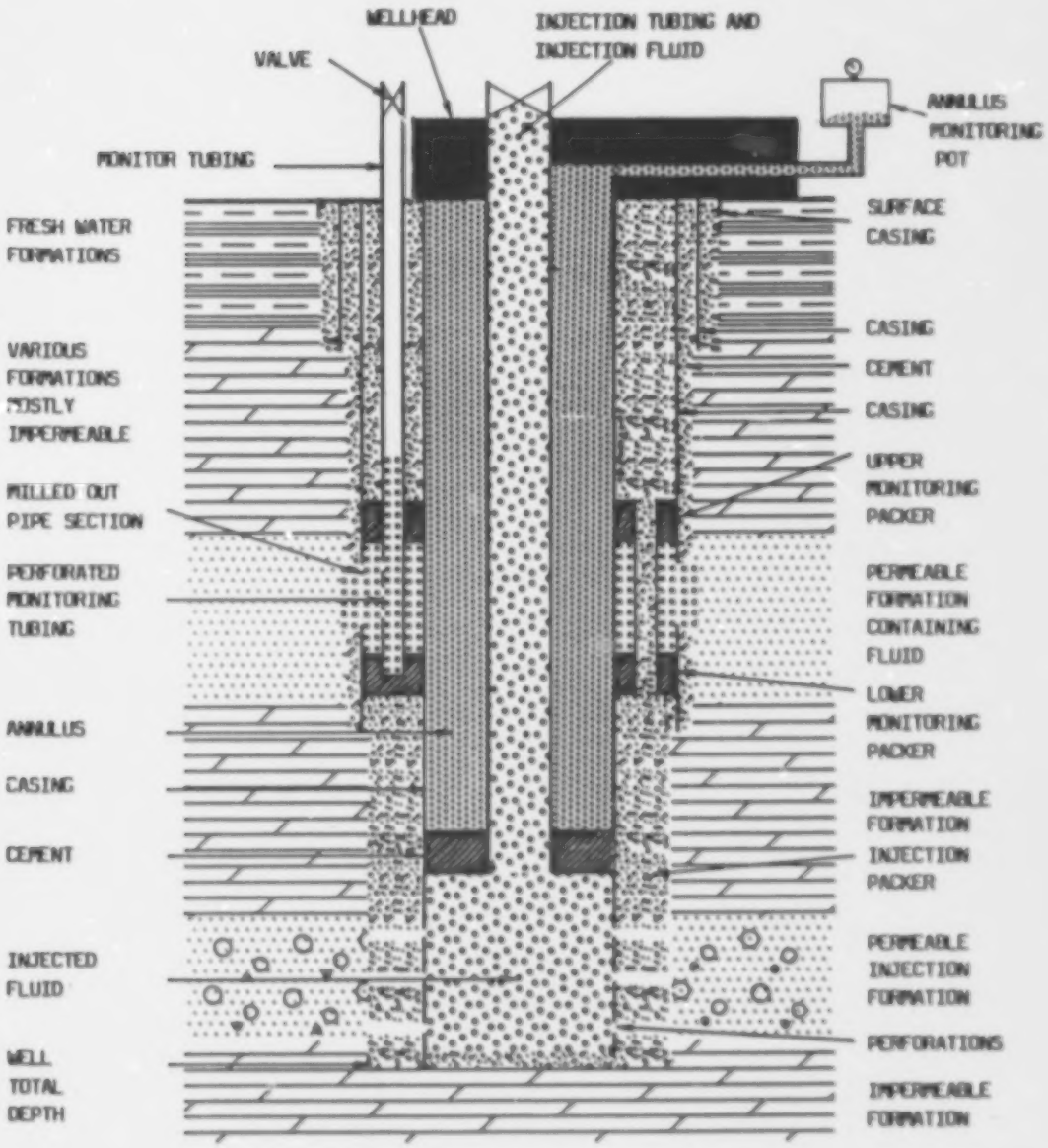
COMPOSIT
INJECTION WELL WITH MONITORING SYSTEM INSTALLED
SAMPLE - SIZES VARY - SCHEMATIC
(POIMBOEUF - BUCK METHOD)
FIGURE NO. 23



INJECTION WELL WITH MONITORING SYSTEM
FOR MONITORING TWO ANNULI
FIGURE NO. 24



COMPOSIT
INJECTION WELL WITH MONITORING SYSTEM INSTALLED
SAMPLE - SIZES VARY - SCHEMATIC
(POIMBOEUF - BUCK METHOD)
FIGURE NO. 25



APPLICATION OF THE CONTINUOUS ANNULAR MONITORING CONCEPT TO PREVENT GROUNDWATER CONTAMINATION BY CLASS II INJECTION WELLS

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ABSTRACT

This paper will present a continuous annular monitoring concept that allows Class II injection wells that have insignificant leaks in the casing to demonstrate mechanical integrity. Inherent in this concept is the premise that an insignificant leak in the casing is any leakthat will not endanger a USDW and that this test will therefore meet the regulatory requirements under 40 CFR 146.8 (a) and (b). A case history will be presented to demonstrate the

viability of this concept as an alternative mechanical integrity test. This concept has been approved as an alternate mechanical integrity test by the Reginal Administrator of USEPA Region 6 for use in the Osage Mineral Reserve under 40 CFR 147.2912 (a) (1)(v).

INTRODUCTION

There are a significant number of Class II wells that have been in existence for many decades. The casing leaks that have developed in these wells have proven expensive to correct in order to meet the strict interpretation of the applicable UIC regulations on the federal and state level. Accordingly, in order to allow the continued use of this type of well without remedial action being performed on the casing until such time as the USDW is endangered, a concept that incorporates a pressure test on the tubing and packer along with continuous annular monitoring was developed. This concept has been successfully implemented on a field operated by Phillips Petroleum Company in Osage County, Oklahoma under agreement with USEPA Region 6.

REGULATORY OVERVIEW

The Environmental Protection Agency Regulations covering the underground injection control program are defined in 40 CFR Part 146. Specifically, the regulations concerning the demonstration of mechanical integrity are put forth in 40 CFR 146.8 and in the applicable sections of 40 CFR 147 which covers the primacy states and Indian Lands and has basically the same requirements as those outlined in 146.8.

40 CFR 146.8 (a) states that an injection well has mechanical integrity if: "(1) There is no significant leak in the casing, tubing or packer; and (2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection wellbore."

All existing wells undergo a technical review to show compliance with 40 CFR 146.8 (a) (2) and this part of the regulation will not be addressed further.

Compliance with 146.8 (a) (1) can be demonstrated under 146.8 (b) which states that "one of the following methods must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section: (1) Monitoring of annulus pressure: or (2) Pressure test with liquid or gas: or (3) Records of monitoring showing the pressure

and injection flow rate for the following Class II enhanced recovery wells:" etc. Subparagraph (3) is not considered relevant to the continuous annular monitoring concept and will not be addressed further.

THE CONCEPT OF CONTINUOUS ANNULAR MONITORING

The continuous annular monitoring concept that is being proposed as an alternate mechanical integrity test is a combination of pressure test on the tubing and packer as well as a monitoring system on the tubing-casing annulus. This concept will ensure that a USDW is not endangered when a well is allowed to operate without demonstrating that the casing will hold pressure.

To qualify for the continuous annular monitoring test, the well must:

1. Demonstrate compliance with 40 CFR 146.8 (a)(2).

2. Have a fluid level greater that 100 feet (30.48m) below the base of the lowermost USDW.

3. Demonstrate mechanical integrity of the tubing and packer using the "ADA Pressure Test" or a radioactive tracer survey if applicable under state regulations.

The test procedures would be:

1. Install a continuous monitoring system which would immediately detect and warn of a fluid level in the casing or tubing-casing annulus within 100 feet of the base of the lowermost USDW.

2. If the fluid level rises to within 100 feet (30.48m) of the lowermost USDW. The operator shall report this situation to the EPA or appropriate regulatory agency with 48 hours. Within five days the operator shall reset the monitoring device to detect the fluid level within 75 feet (22.86m) of the base of the lowermost USDW.

3. If the fluid level rises to within 75 feet (22.86m) of the lowermost USDW, the operator shall report this situation, including change in fluid level in feet per day, to the EPA or appropriate regulatory agency within 48 hours. Within five days the operator shall reset the monitoring device to detect the fluid level

within 50 feet (15.24m) of the base of the lowermost USDW.

4. If the fluid level rises to within 50 feet (15.24m) of the lowermost USDW, the operator shall immediately shut-in the well (if active) and report this siutation including the change in fluid level in feet per day, to the EPA or appropriate regulatory agency within 48 hours.

If the fluid level does not remain more that 50 feet (15.24m) below the base of the lowermost USDW, the well would fail the mechanical integrity test and the operator shall submit to EPA or the appropriate regulatory agency, within 15 days: (1) A plan to lower the fluid level in the annulus, or (2) A plan to repair the well, or (3) A plan to properly plug and abandon the well. The plan shall include a schedule for completing the required work as long as the well is passing the continuous annular monitoring test the actual fluid level in the tubing-casing annulus shall be measured at least twice a year and reported to the USEPA or appropriate regulatory agency with the annual report. The tubing and packer must be pressure tested every five years or whenever the packer is unseated for any reason.

The rationale behind the development of this test is that regardless of the condition of the casing, a USDW cannot be endangered if the formation pressures below the USDW are not great enough to support a column of fluid at the same level as the USDW. Since the static fluid level in the annulus is directly related to the reservoir pressure existing at the time the packer was set, it can be assumed that any change in the formation pressure that would endanger the USDW would be picked up by the monitoring device when the static fluid level changed. Any change in the static fluid level would indicate that there was a tubing-packer failure or there was migration of fluids behind the casing that was communicating through the casing leaks, therefore, causing a fluid level rise in the annulus.

The theory and operation of the continuous fluid level monitoring device was tested by Jerry Thornhill of the USEPA Robert S. Kerr Environmental Laboratory in Ada, OK, on January 22, 1990.

The device was successfully tested on the ECU/EPA Research well by detecting a rise in the annulus fluid level and activating the alarm with the fluid raising to no greater than one foot (30.5 cm) above the trigger depth. These depths and conditions were verified by two

acoustic fluid level measuring devices and a manually operated cable type fluid level measuring device.

ADVANTAGES

This concept has several inherent advantages over the standard pressure test that is required to be performed every five years.

A major advantage is that the well is, in effect, continuously tested for physical integrity of the tubing and packer as well as for any vertical migration that may be occurring through vertical channels adjacent to the well bore. This migration would be communicated through any leaks in the casing and manifest itself as a change in the static fluid level in the tubing-casing annulus. Although a well may pass the pressure test, there is no guarantee that the well would pass the same test at any time in the future. Should the casing, tubing or packer fail, and industry experience indicates that a failure can be expected before the five year retest, the well may operate for a considerable period of time before the failure is discovered. With the continuous annular monitoring, once there is a rise in the tubing-casing annulus fluid level, the device would immediately and visibly report the situation, therefore, allowing either the operating personnel or the regulatory inspectors to easily notice the problem.

The application of this concept as an alternative mechanical integrity test also allows an operator an economic savings as long as the well remains within the contraints of the test procedures. It can be conservatively stated that under the vast majority of cases, an operator could be expected to expend a minimum of USD 3000 to repair a casing leak. The cost of plugging and abandoning a well, should the leak be unrepairable, would range from USD 1500 up depending on well construction and problems encountered. The operator would also incur a significant cost in replacing the well that was plugged or, in the worst case, have to plug out the entire lease if production revenue would not support the construction of another well for injection purposes. This probblem could be effectively resolved by the application of the continuous monitoring concept as an alternative mechanical integrity test.

CASE HISTORY

The North Burbank Field, located in Osage County, Oklahoma, was discovered by Marland Oil Company in May, 1920. The producing formation is approximately 3,000 feet (915m) deep and extends 12 miles (19.3km) north to

south and 4-1/2 miles (7.25km) east to west. Original oil-in-place was 671,000,000 STB (107,000,000 m^3). The field was unitized in 1950 with Phillips Petroleum as operator. Today, the field is under waterflood with a total of 721 producing wells and 561 Class II injection wells. Currently, only 165 producing wells and 73 Class II injection wells are active. Cummulative production to date is 310,000,000 STB (49,300,000 m^3).

The wells, drilled from the 1920's through the 1960's, were completed with large surface casing set to an average depth of 120 feet and cemented to surface. Production casing was set to a depth of approximately 2900 feet (884m) and cemented with an average of 75 sacks of cement. The well was then cable tool drilled through the producing zone and completed openhole. (See Figure 1.)

In 1984 the Osage County Underground Injection Control (UIC) regulations became final (See Figure 2.) Early in 1985 they went into effect requiring that owner/operators of Class II injection wells demonstrate well mechanical integrity according to 40 CFR 147.2912 (a), which included:

1. A review of casing and cementing records to demonstrate that there is no significant fluid movement into a USDW through vertical channels adjacent to the wellbore (40 CFR 147.2912 (a)(2), and

2. A field test of the well to demonstrate that there are no significant leaks in the casing, tubing, or packer (40 CFR 147.2912 (a)(1).

According to the UIC regulations, if a Class II injection well failed to demonstrate mechanical integrity, the owner/operator was required to remove the well from service. At that point the well had to be repaired, converted to a producer, or plugged and abandoned.

During 1987, all Class II injection wells operated by Phillips Petroleum in Osage County were submitted for technical review. During 1988, following that technical review, all Phillips operated Class II injection wells were either tested for mechanical integrity of the casing, tubing, and packer with a 200 psi (1380kpa) pressure test, or submitted as verbal failures of the mechanical integrity test. At that time the field contained 561 Class II injection wells. A total of 45 wells passed the casing, tubing, and packer integrity test and 516 wells failed.

Due to the magnitude of the number of wells that failed, and the resulting operational impact that casing repair of plug and abandonment would have on the economic viability of the field, Phillips, as operator of the North Burbank Field, requested the opportunity to test the continuous annular monitoring concept. That request was granted by the USEPA Region 6 Regional Administrator in October, 1988.

In approving the test of the concept, the USEPA placed the following general requirements:

1. If mechanical integrity tests demonstrate casing leaks, or if Phillips admits the presence of casing leaks, then Phillips will implement the monitoring program for active wells with such leaks and for all inactive wells that do not have mechanical integrity.

2. Phillips would test the mechanical integrity of the tubing and packer of all active wells in the North Burbank Unit. Pursuant to 40 CFR 147.2912.

3. Phillips would install on each active and inactive well described above, a continuous monitoring system which would immediately detect and warn of fluid level in the casing-tubing annulus within 100 feet (30.48) of the base of the lowest USDW. Beginning upon signature of the Agreement, the systems would be installed at a rate of forty-five (45) per month, with active wells given priority. All required monitoring systems to be installed by December 31, 1989.

Based on the requirements outlined above under the concept of continuous annular monitoring, Phillips developed corrective action plans for certain Class II injection wells that failed to demonstrate mechanical integrity, but that would continue to be operated as injection wells. (See Figure 3.) In all wells have a tubing-casing annulus fluid level <u>above</u> the USEPA specified base of the USDW and a fluid level in the tubing <u>below</u> the base of the USDW, the fluid level would be lowered below the base of the USDW by releasing the packer. This action will allow the tubing-casing annulus fluid to equalize with the fluid level supported by the producing formation is evidenced by the tubing fluid level. Since the fluid level in the tubing is below the base of the USDW, the resulting fluid level in the annulus would likewise be below the base of the USDW.

In all wells having a tubing-casing annulus fluid level and tubing fluid level above the USEPA specified base of the USDW, the fluid level would be lowered below the base of the USDW by removing the tubing and packer and placing a blanking plug in the well above the injection zone. The fluid level would then be swabbed down to a point below the base of the USDW.

Following both of these corrective action plans, a FLMD is installed on the well.

Similar corrective action plans were developed for those Class II injection wells that would be temporarily abandoned. (See Figure 4.)

DESIGN

The continuous monitoring system as proposed by Phillips utilizes a fluid level monitoring device (FLMD) that was designed by a group of Phillips engineers lead by Mr. C. D. Fryer. This monitoring device ensured that any fluid level which rose to near the base of fresh water would be readily detected.

The FLMD contains two separate sections; a monitoring side and an alarm side (See Figure 5.) The monitoring side is based on the ideal gas law and consists of a diaphragm and 1/4 inch (6.35mm) stainless steel tubing. The stainless steel tubing is placed in the tubing-casing annulus to a pre-calculated depth. The setting depth is based on the depth of the USDW and the warning margin desired, and calculated by the following formula:

$$Lt=(((Pd(Vd2+VtLw))/Pa)-Vd)/Vt \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

Where Lt = Length of stainless steel tubing, feet
Lw = Warning level (USDW + warning margin), feet (m)
Pa = Atmospheric pressure, psia (Pa)
Pd = Diaphragm trigger pressure, PSIA (Pa)
Vd = Volume above diaphragm at atmospheric pressure, 1.83 cu. in. (3×10^{-5} m^3)
Vd2 = Volume above diaphragm at trigger pressure, 3.66 cu. in. (6×10^{-5} m^3)
Vt = Internal volume per foot of 1/4 inch (6.35mm) stainless steel tubing, 0.3054 cu. in./ft (1.64×10^{-5} m^3/m)
Lw = Warning level (USDW + warning margin), feet (m)
Pa = Atmospheric pressure, psia (Pa)

Example: USDW = 100 FT (30.48m)
Warning margin = 100 ft (30.48m)
Trigger pressure = 2.5 psig (17.24 kPa)
Atmospheric pressure = 14.4 psi (99.28 kPa)

Lt = (((Pd(Vd2+VtLw))/Pa)-Vd)/Vt

Lt = 243 feet (74m) of 1/4 inch (6.35mm) stainless steel tubing

In this example, the stainless steel tubing would be placed in the tubing-casing annulus to a depth of 243 feet (74m). Once attached to the diaphragm the diaphragm would trigger if the annulus fluid level rose to a depth of 200 feet (60.96m) from surface. This would be 100 feet (30.48m) below the base of the USDW. This "triggering" is accomplished by the compression of the air in the stainless steel tubing and above the diaphragm as the fluid level in the annulus raises from the end of the stainless steel tubing at 243 feet (74m) to the warning level of 200 feet (60.96m) (USDW plus warning margin).

Once the monitoring side of the FLMD has sensed a rise in the tubing-casing annulus, the alarm side goes into action. The alarm side consists of a pressurized tank, a valve, and a warning flag mounted on an air ram. When the diaphragm is triggered, it opens a valve. The valve then allows pressure from the pressurized tank to charge the air ram. The charged air ram then raises the warning flag in the air to signal a high fluid level in the tubing-casing annulus.

The physical environment that the FLMD would be required to operate in necessitated that the device be compact, unobtrusive and attach to existing wellhead equipment with minimal modification (See Figure 6.) Due to the number of FLMD's to be installed, total installed price per unit had to be maintained as low as possible. The time frame for installation set by the USEPA demanded that the FLMD's be built from equipment available off the shelf and easily serviced.

INSTALLATION

Installation of the FLMD is identical for an active or inactive Class II injection well. However, to remain active a Class II injection well must first pass a tubing and packer integrity test. The nitrogen method of integrity testing was utilized at North Burbank. The method required that the tubing and wellbore below the packer be filled with nitrogen and the surface pressue on

the tubing-casing annulus as well as the tubing be monitored for pressure changes resulting from tubing or packer leaks.

The installation procedure for the FLMD is as follows:

1. Modify the rubber seal ring of the wellhead and adjust the tubing slips to facilitate the monitoring tube.
   NOTE: Some types of slips will require removal and modification.

2. Install stainless steel monitoring tube to predetermined depth.

3. Modify wellhead to accept FLMD. Attach FLMD to wellhead.

4. Test stainless steel monitoring tube to ensure it is not blocked. Clear if required.

5. Complete installation by attaching the FLMD to the stainless steel monitoring tube and pressurize the FLMD's air tank.

To date a total of 487 FLMD's have been installed in Class II injection wells in the North Burbank Field. During 1989, a total of 45 monitoring devices detected a high tubing-casing annulus fluid level. Twenty-four of the signals resulted in corrective action to the wells. Twenty-one of the signals were either false signals or premature signals.

Total compliance with USEPA MIT requirements for Class II injection wells in the North Burbank Field without use of the approval of the continuous monitoring concept was estimated at USD 7.2 MM. By utilizing the continuous monitoring concept compliance for the North Burbank Field totaled USD 600,000.

On December 20, 1989, USEPA Region 6 made this an alternate mechanical integrity test as per the Regional Administrator Authority under 40 CFR 147.2912 (a)(1)(V).

This approval applies only to the Osage Mineral Reserve and allows an operator to choose between the positive pressure test of casing or the continuous monitoring concept. (See Figure 7.)

PROBLEMS

Two areas of problems have been encountered during the

installation program of the FLMD. The first problem area is system air leaks on the alarm side of the device. These are being addressed and steps are being taken to eliminate as many potential leak points as possible. The second area is plugging of the monitor tubing during installation. This problem has been solved with the use of a low volume high pressure pump to clear the monitor tubing after installation.

Alternate methods of warning have been tested and reviewed. Electrical signals such as flashing lights or sirens, as well as the mechanical flag signal have been tested. Due to the operating parameters in the North Burbank Field, the mechanical flag warning signal was chosen.

PROGRAM MAINTENANCE

The continuous monitoring system as installed at North Burbank requires cooperation of all persons involved in the field. Everyone has been trained to look for flags as they travel the lease roads. The air pressure is checked on the monitor devices by the field pumpers twice a month. Twice a year the monitoring device is function tested and preventive maintenance done on the device. During this function test, the tubing-casing fluid level is determined by an acoustic fluid level measuring device to confirm the fluid level is below the base of the USDW.

SUMMARY

The application of the continuous annular monitoring concept as an alternative mechanical integrity test on Class II wells with insignificant leaks in the casing is a practical means of achieving compliance with UIC regulations. Oil and gas producing companies can realize significant economic savings since expensive remedial operations would not have to be performed on every well that could not pass a standard pressure test on the tubing-casing annulus. In addition, this concept would allow for regulatory agencies to quickly and easily check for well problems that might go undetected for a considerable length of time under the normal five year test schedule.

REFERENCES

Wilson, Everett M.: "EPA Develops Injection Well Pressure Test"

Petroleum Engineer International March 1988 (Pg. 34-39) and April 1988 (Pg. 40-47).

ACKNOWLEDGEMENT

The authors thank C. D. Fryer, Phillips Petroleum Company, who designed and patented the monitoring device. His efforts as well as the efforts of the staff of USEPA 6W-SE were instrumental in obtaining the USEPA Region 6 Regional Administrators approval of the continuous monitoring test program. Without their work this article would not have been possible.

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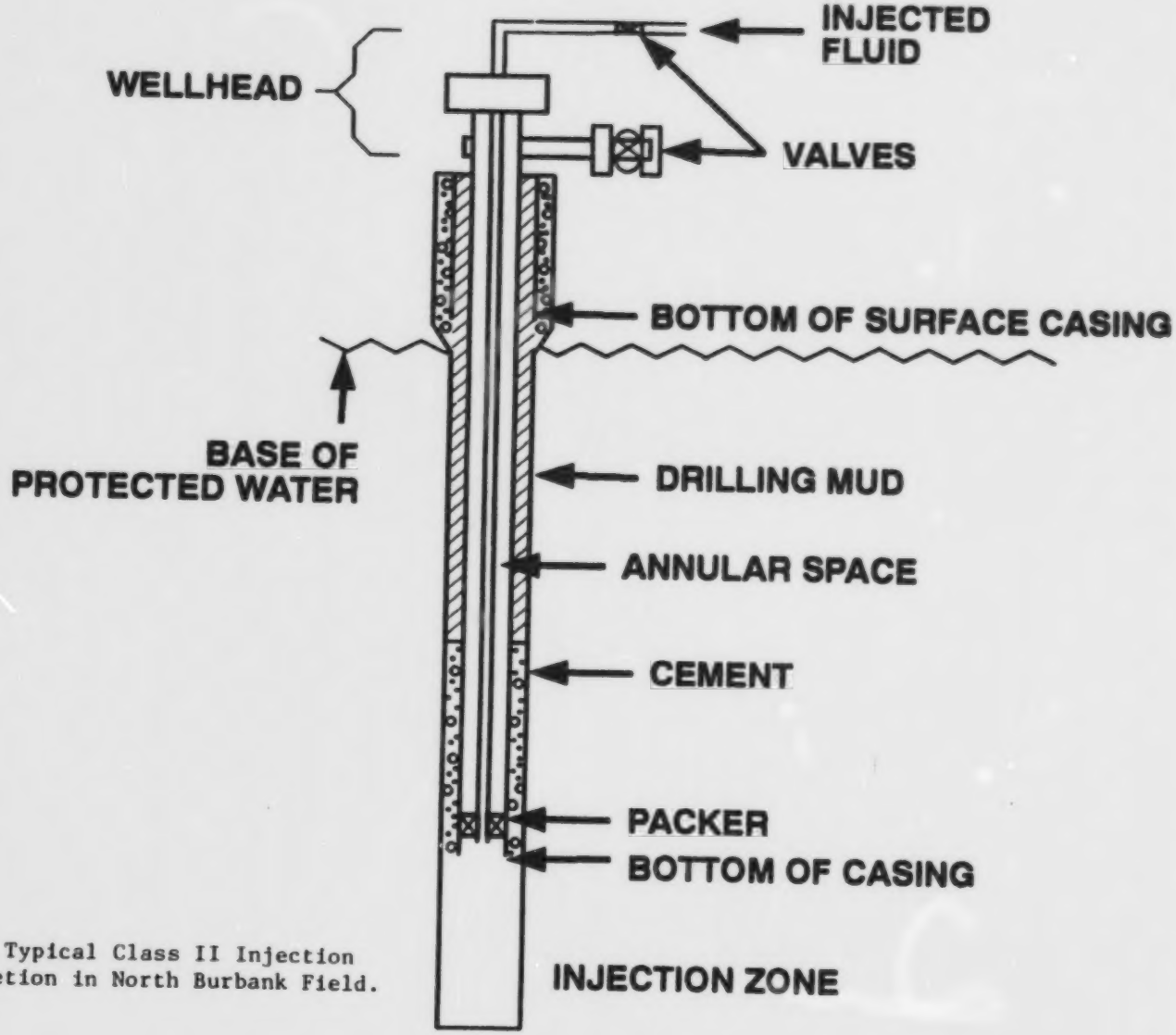

Figure 1. Typical Class II Injection Well Completion in North Burbank Field.

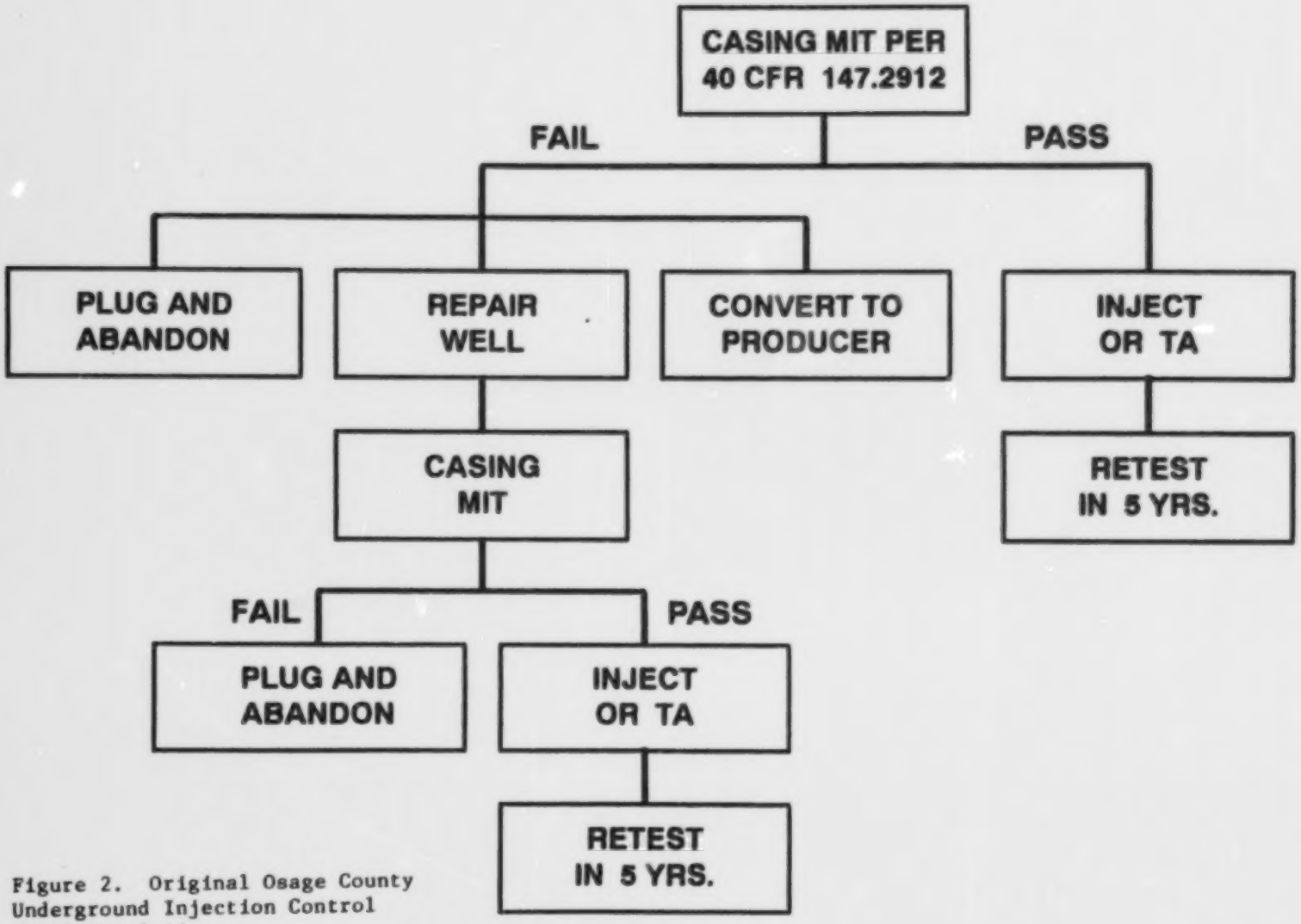

Figure 2. Original Osage County Underground Injection Control (UIC) Regulation.

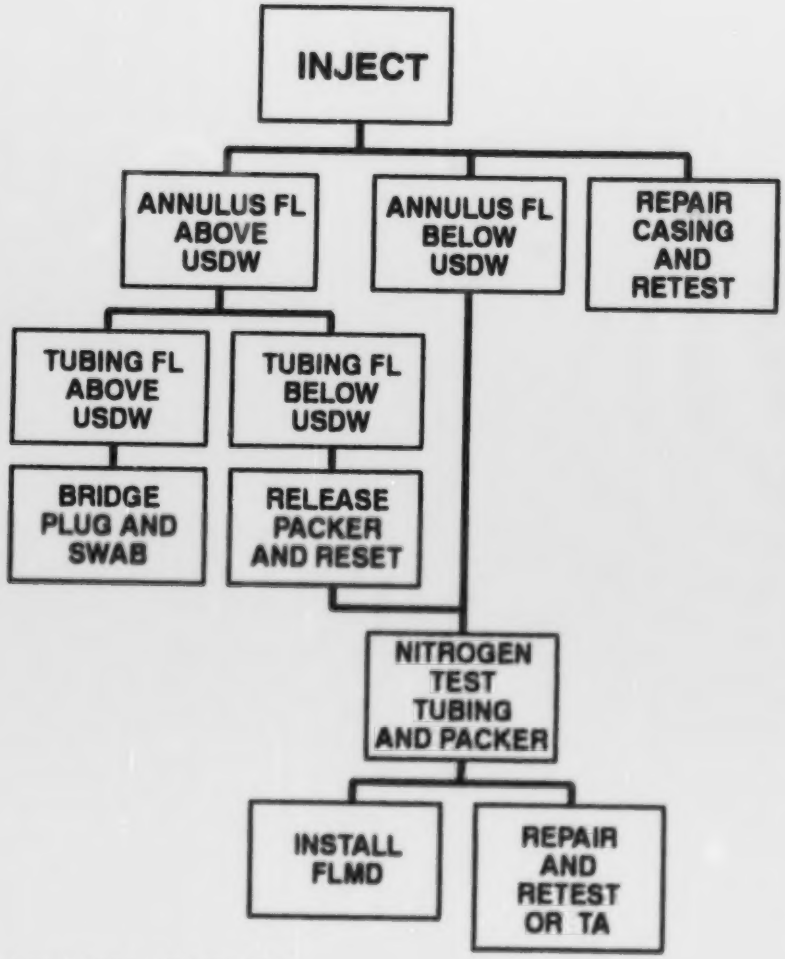

Figure 3. Corrective Action Plans Under Test Program for Active Class II Injection Wells.

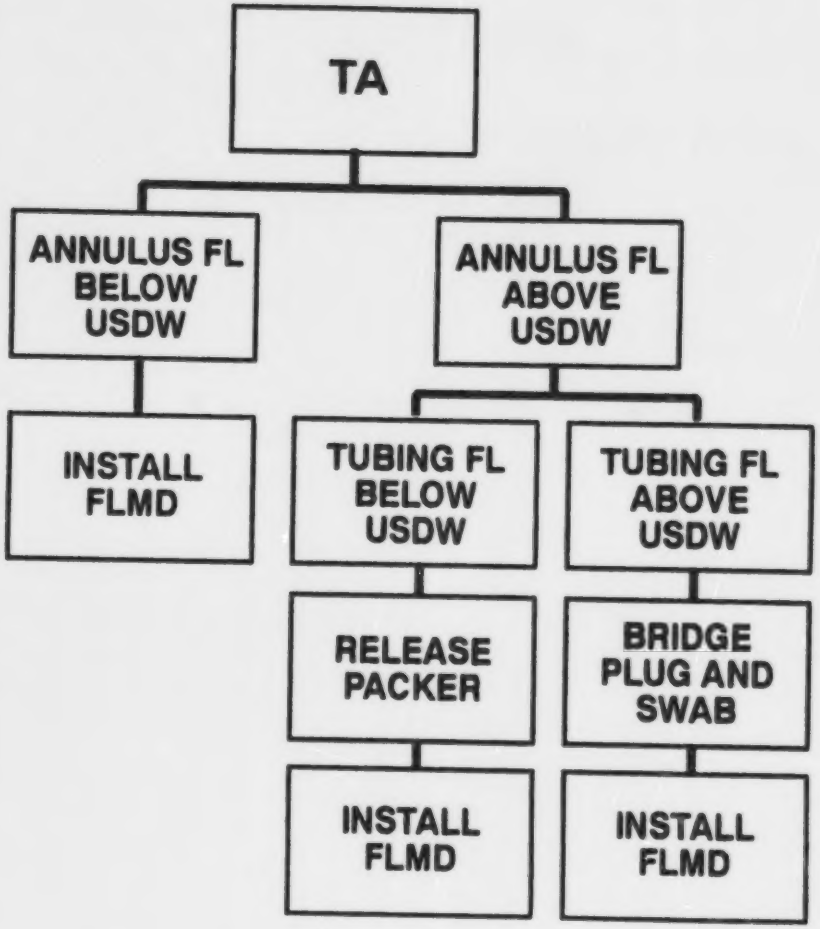

Figure 4. Corrective Action Plans Under Test Program for Temporarily Abandoned Class II Injection Wells.

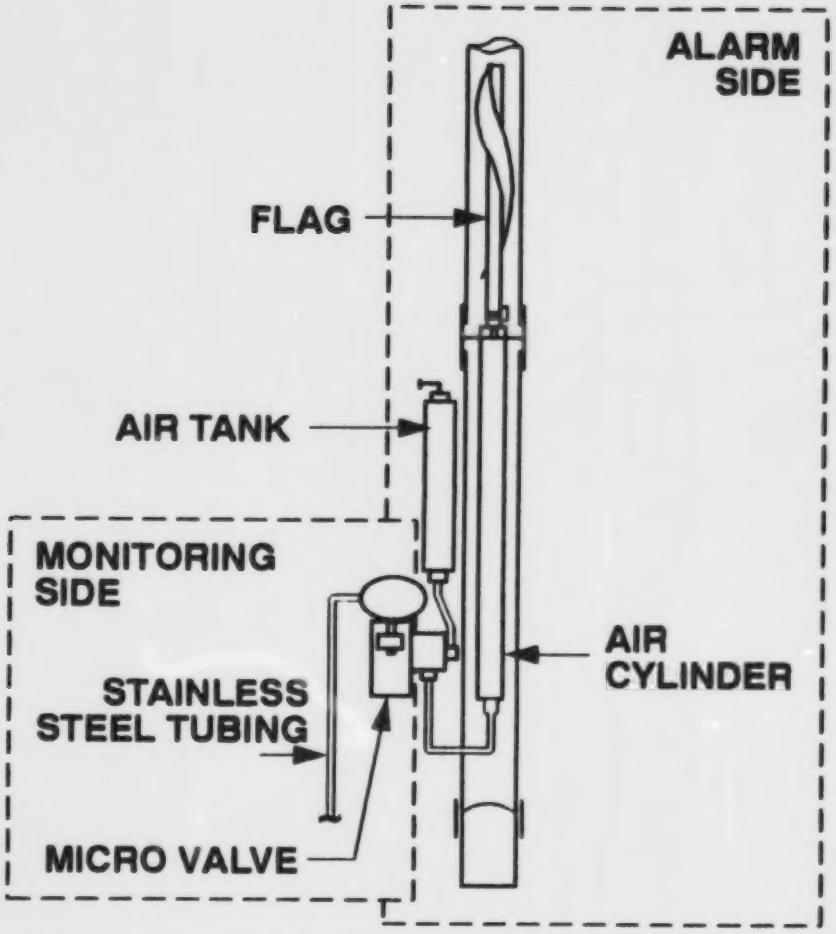

Figure 5. Fluid Level Monitoring Device.

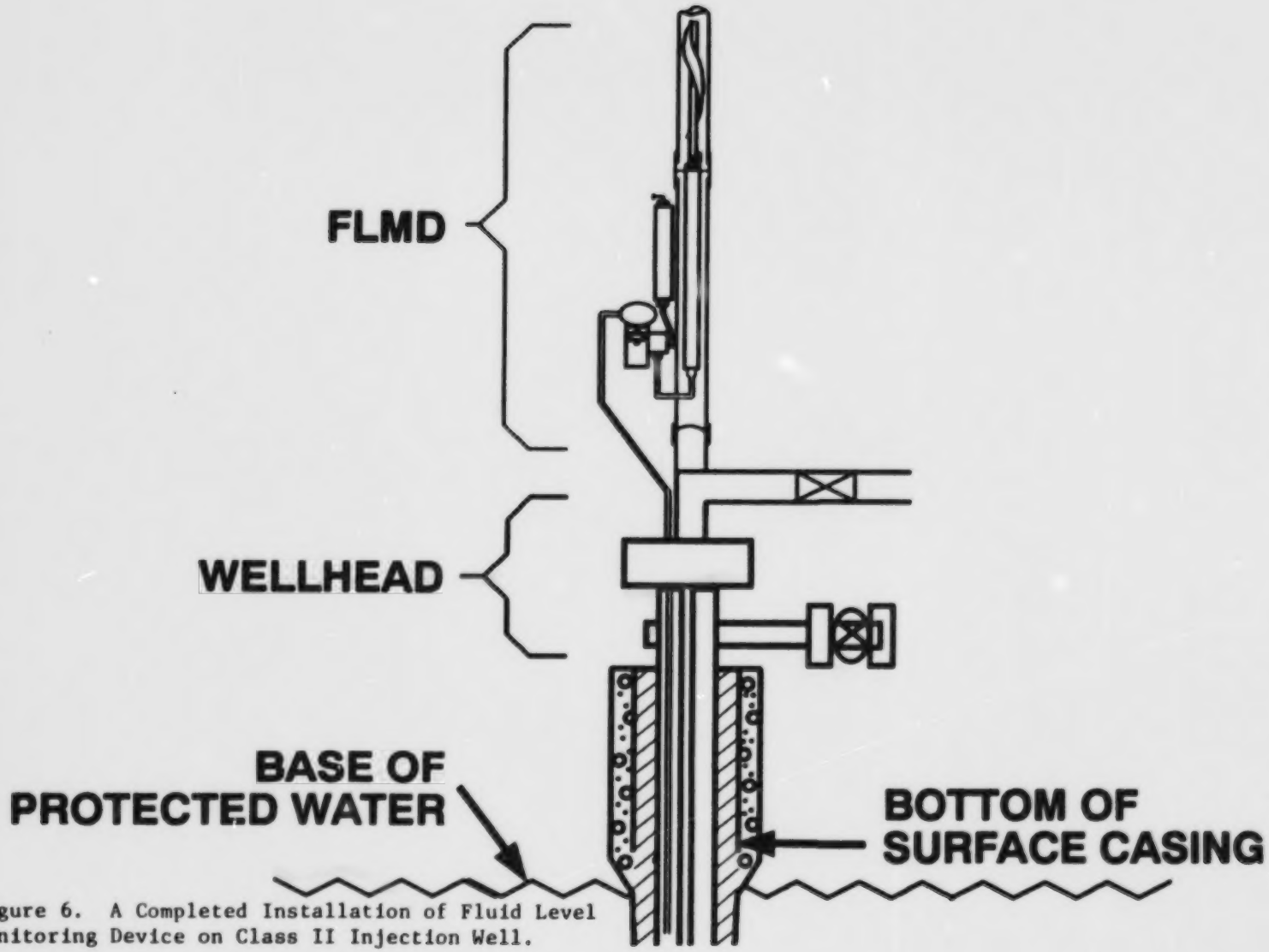

Figure 6. A Completed Installation of Fluid Level Monitoring Device on Class II Injection Well.

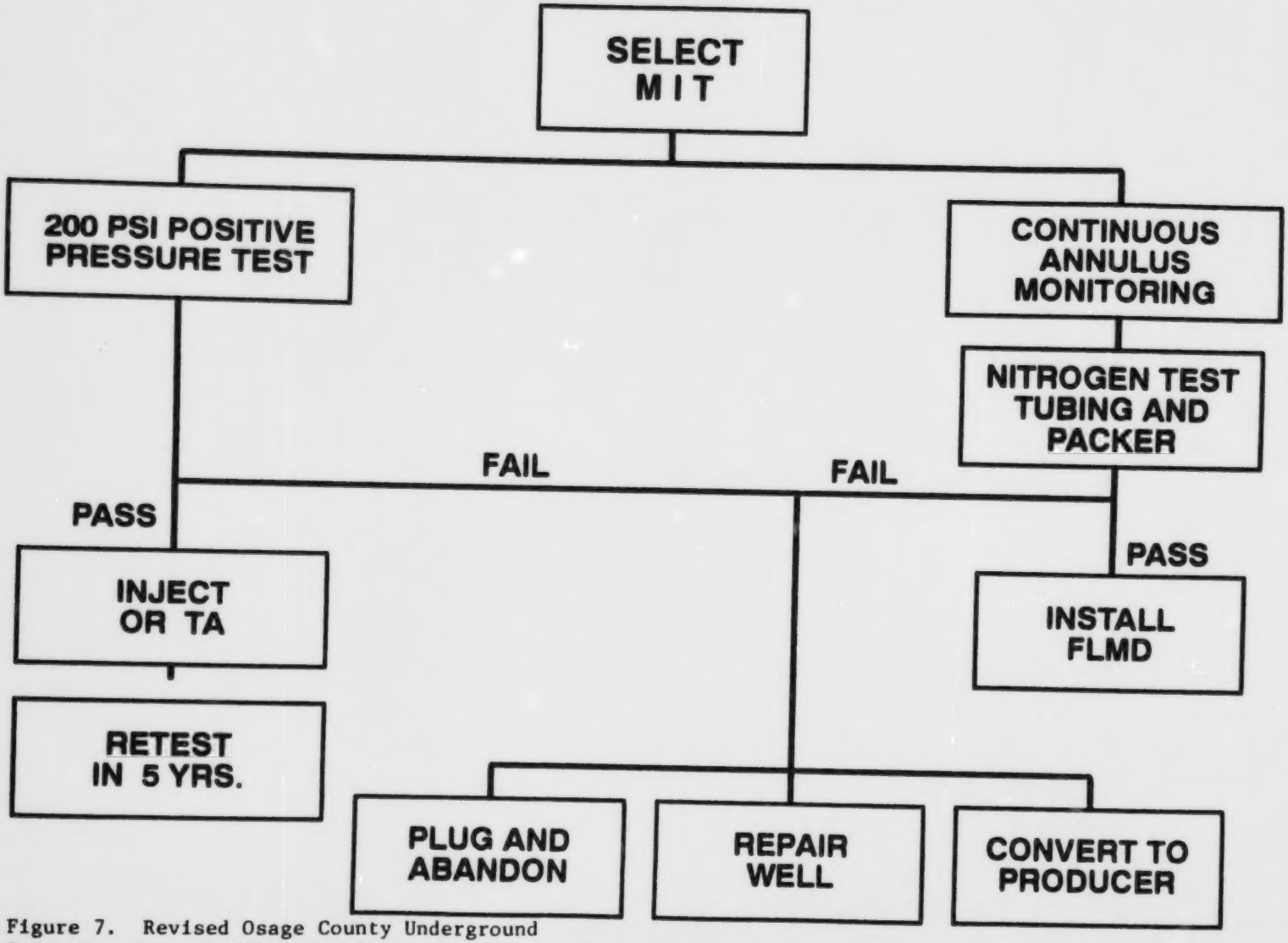

Figure 7. Revised Osage County Underground Injection Control (UIC) Regulations Following Test Program.

AREA WASTE MANAGEMENT PLAN FOR DRILLING AND PRODUCTION OPERATIONS

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INTRODUCTION

One environmental issue receiving significant attention in recent years within the oil and gas exploration and production industry is the handling and disposal of wastes generated by the various drilling and production operations. Heightened interest within the public and regulatory agencies toward environmental issues has been an impetus for the industry to scrutinize its wastes and how they are managed.

From a private company's perspective, proper waste management is an important part of doing business. A company must be concerned with compliance with applicable waste regulations, minimizing the impact of wastes on the environment, and the reduction of potential liability associated with improperly disposed waste. This must be accomplished all within the certain economic bounds. Also, eliminating or minimizing the generation of waste is becoming more critical - both environmentally and economically - as a means of reducing waste-related liabilities and costs.

This paper reviews the concept of the Area Waste Management Plan (Plan) as a means of improving the management of wastes generated by a company's drilling and production operations. The development and use of Area Waste Management Plans, as described in this paper, allow a company to effectively identify and communicate sound waste management strategies. These strategies are based on the regulatory, environmental, technical, and economic criteria applicable to a specific geographic area's operations. The development, content, format, and possible alternative applications of the Plan are presented.

WASTE MANAGEMENT CONCERNS

Upon a cursory review of the Company's drilling and production operations, several concerns were identified regarding the handling and disposal of certain wastes generated by its operations. Production operations reviewed were from a broad scope of operating facilities, including oil production (both primary and secondary), gas production, and gas processing plants. Drilling operations observed included drilling, workover, and completion operations. These field operations were situated in a variety of environmental and regulatory settings.

Waste management concerns generally manifested themselves in inconsistent minimization, handling and disposal practices. In reviewing the operations themselves and interviewing operations personnel, specific reasons these waste management concerns became evident.

The primary reason for the waste management concerns was a lack of understanding of the wastes and the management options available for their handling and disposal. This was due to several factors, including a complex and changing regulatory climate, lack of clear guidance on the environmental aspects of field

operations, and the perception of competing environmental and economic goals.

Regulatory Climate

Most state oil and gas agencies began regulating waste from drilling and production operations before the inception of many of the federal environmental statutes passed in the early 1970s. Historically, regulation of wastes in the oil field focused on drilling fluids and produced water.

Since the early 1970's, a number of the federal environmental statutes, and subsequent state statutes and regulations, have been passed which affect the management of oil and gas waste. Each state has developed regulations to control these wastes as specified in the federal laws, and as specified in the individual state's environmental statutes. For operations on federally controlled land, separate and overlapping regulations administered by the respective federal agencies (e.g. BLM, Forest Service) must be complied with, in addition to state requirements.

Though adequate, individual states' requirements for oil and gas waste management vary significantly. This variability reflects the diverse geological and environmental conditions in each state. Often attributed to the historical emphasis on drilling fluid and produced water, the regulations are often not specific on a waste by waste basis. Additionally, most environmental regulations have been amended frequently over the last ten years.

This complex regulatory climate, which changes with time and with geo-political boundaries, contributes significantly to the lack of understanding of compliance requirements affecting waste management in the oil field.

Management Options Not Understood

In the operations reviewed, many viable waste management options allowed by the applicable regulation were not being utilized. This was primarily due to a lack of understanding of the available options which met the appropriate regulatory, environmental, company policy and economical criteria. Operations personnel responsible for waste management at each facility had inadequate resources available for determining and choosing among the feasible options.

Adequate guidance from regulatory agencies was generally not available. Copies of the applicable regulations were readily available, but commonly these regulations were not clearly written for individuals not familiar with regulatory documents. Internal guidance from the company was often unavailable or inadequate. Several reasons for this were:

- Relevant company policies on waste management were too general;
- Environmental personnel (staff) who were knowledgeable on the regulatory, environmental, and technical aspects of waste management were not knowledgeable in field operations; and
- The 1980's business climate - profit margins and support staffs have been reduced at the same time concern for the environment has increased.

With no usable guidance, field operations personnel frequently decided unilaterally on methods of handling and disposing of wastes. This often resulted in wastes being managed in ways which, though historically acceptable, were without full consideration of the regulatory and environmental criteria which possibly applied. Conversely, some operations were using over-conservative waste management practices, when equivalently compliant and protective methods were available that were less costly.

Needs Assessment

The following is the needs assessment resulting from the identification of the

waste management problems and their root causes:

1. Improve Understanding of Wastes and Waste Management Requirements and Options
2. Establish Waste Management Goals and Performance Standards
3. Improve Communication and Implementation of Goals and Standards

AREA WASTE MANAGEMENT PLAN

The concept of the Area Waste Management Plan, as described below, is intended to address the stated needs in the following manner:

1. Provides a process to identify appropriate management strategies (i.e. minimization, handling, and disposal practices) for wastes generated by production or drilling operations; and
2. Provides an effective means of communicating those strategies so they may be implemented effectively.

In identifying appropriate waste management strategies, all relevant criteria are considered, including regulatory, environmental, company policy, practical, and economical. As important as identifying sound waste management practices, is ensuring they are properly implemented. The second component of the Plan is the development and use of a user-friendly document which provides effective guidance to field operations personnel requiring the information.

Much of the regulatory and technical information required to identify acceptable management options for specific drilling and production waste was addressed generally by the American Petroleum Institute in its document entitled *Environmental Guidance Document for Onshore Solid Waste Management in Exploration and Production Operations (API/EGD)*[1]. The development of the Area Waste Management Plan uses and builds upon the regulatory and technical information contained in the API/EGD.

Development of Plan

The first phase of the Plan process consists of identification of wastes and guidance on the management of those wastes. A Plan is developed using a rigorous step-wise process of identifying wastes, then selecting and prioritizing management options (i.e. minimization, handling, and disposal practices for each waste).

Throughout the development process, the involvement of field personnel (several levels are preferred - supervisors to roustabouts) is critical to: a. identify all waste streams and management options; and b. to ensure their support of the Plan when published.

Each step in this waste management practices selection exercise is described below. With each step, examples are given from the development of an actual Plan for the Company's Southeast New Mexico Production Operation[2]. A brief summary of this six-step process is found in Table 1.

Step 1: Identify Area of Coverage

A logical scope for the Plan must be defined by selecting the area which the Plan will cover. Developing one cohesive Plan to cover all the operations in a company is generally not possible unless the operations are limited geographically or operationally. It is assumed, therefore, that initially a company's operations must be divided into several "areas" for the purpose of developing the Plan for each. On the other hand, a company's operations should not be divided into so many Areas that there are too many individual Plans to practically develop and maintain. In defining an Area of Coverage for the Plan,

the primary goal is to define areas with common aspects which may affect waste management strategies. An Area should be defined by operational, as well as geographic or areal, boundaries.

Defining an area geographically should be based primarily on common regulatory requirements, environmental, and geological characteristics. Areas based on the applicable waste regulations usually follow state (or other geo-political) lines which define regulatory jurisdiction. An Area may also be defined geographically, based on common environmental and/or geological aspects. The surface environment where an operation exists often influences the various management options available. The geological (i.e., reservoir) aspects influence the nature of production and drilling wastes generated.

A geographically-based Area can be further refined by determining the relative benefit of defining the Area based on common operations. It may be effective to develop separate Plans for each of the major types of operation - namely drilling, production, or gas processing plant. Another method to consider in defining an Area is to have separate Plans for each operational organization. In some cases, an Area defined by organization (e.g., Area Plan for Production Dept.) allows more customizing with respect to the ultimate user of the Plan.

Example of defining an Area: In defining the Area for the Southeast New Mexico Production Operations' Plan, the following rationale was used:

- Regulatory: Oil and gas wastes are primarily regulated by the New Mexico Oil Conservation Division (NMOCD), therefore the initial area definition was by state. The two primary oil and gas regions in New Mexico are in the Northwest (NW) and Southeast (SE) corners of the state. One reason for dividing the state in two is the regulatory agency jurisdiction--the NW has a large percentage of federal and Indian land and the SE is predominately privately owned.

- Environmental: The two regions are also distinct in their environment. The NW is a high plateau region crossed with several large river basins. The SE is very much like West Texas, flat with little surface water.

- Geological: Gas is the primary product from the San Juan Basin in the NW. The SE is an extension of the Permian Basin, which is a mature oil and gas producing region. The difference in the resource products also causes a difference in the nature of the wastes.

- Operational: Three operational considerations influenced the definition of the Area:

  1. Waste management options vary between the two regions, partially due to the differences in the service industry which has evolved in each region.
  2. Separate production offices manage the NW and SE operations, giving another reason for dividing the state's operations in two.
  3. Separate Plans were developed for Drilling and Production Operations because the two are managed by separate departments within the Company.

Step 2: Identify Wastes in Area's Operations

Once an Area is defined, all wastes generated by the operations need to be identified. This is best done on a process by process basis. The primary processes associated with drilling and production operations, and wastes generated from those processes, are summarized in the API/EGD. In addition to wastes generated directly from the drilling or production process, many wastes

are generated through indirect activities. These include wastes from vehicles, maintenance activities, office or living quarters in remote locations, and infrequent or unexpected activities. An example of a waste generated by an infrequent activity is residue from a well treatment with a special chemical. Unexpected activities may include product or chemical spills, or the discovery of friable asbestos in an insulated vessel or building.

Example of Area's Waste: Waste identified as being generated, or potentially being generated in the SE New Mexico area are listed in Table 2.

Step 3. Categorize Wastes

Once an Area's wastes have been identified, they must be categorized. Categorizing the wastes as they are defined by the applicable regulations is necessary to ensure they are managed in compliance with those regulations. Even though oil and gas wastes are regulated under varying state programs, all programs must adhere to several basic waste definition principles established under the federal Resource Conservation and Recovery Act (RCRA)[3]. RCRA is the federal statute which regulates solid waste ("solid waste" can be solid, semi-solid, or liquid wastes). In developing the RCRA statute, Congress recognized the special nature of oil and gas exploration and production wastes, and exempted them from hazardous waste regulations. This "exemption" is the key to categorizing oil and gas wastes in order to facilitate their proper management under the various regulatory scenarios found nationally.

The Environmental Protection Agency (EPA) listed specific oil and gas wastes as "exempt" or "nonexempt" in its Regulatory Determination submitted to Congress in June 1988. Using this Determination as a basis, all oil and gas wastes generated in an Area may be divided into the following major categories:

- *Exempt Waste* - Wastes generally coming from an activity directly associated with the drilling of an oil or gas well or the production and processing of a hydrocarbon product. These wastes are considered non-hazardous industrial wastes under RCRA and under state statutes following RCRA. Some states have a narrower interpretation of *Exempt Waste*, which should be considered in categoring specific wastes in those states.

  Example of Exempt Waste: Bottom Sediment and Water (BS&W or tank bottoms) is the non-saleable fraction of the production stream which settles in the bottom of storage tanks and process vessel. Since BS&W comes from the vessels directly associated with production, this waste is categorized *Exempt*.

- *Nonexempt Waste* - Waste coming from the maintenance of production or drilling equipment, or otherwise not unique to the oil and gas exploration and production industry. Though *nonexempt*, these wastes are not necessarily hazardous.

Because *Nonexempt Wastes* are potentially subject to RCRA's hazardous waste regulations (RCRA Subtitle C), they must be subdivided to ensure proper management:

- *Nonexempt Non-Hazardous Waste:* Wastes which are neither listed characteristically hazardous as defined by the RCRA regulations. These wastes can generally be managed as non-hazardous industrial waste, similar to exempt wastes, under most state regulations.

- *Nonexempt Hazardous Waste:* Wastes which are either listed or characteristically hazardous as defined by RCRA regulations. These wastes must be managed as hazardous wastes under the respective state and federal regulations.

Example of Nonexempt Waste: Waste hydrocarbon based solvents generated from cleaning production equipment are classified *Nonexempt* because they are associated with a maintenance activity not necessarily unique to the oil and gas industry. Some waste solvents are classified *Nonexempt Hazardous* due to being characteristically hazardous for failing the RCRA ignitability test[4]. Others exhibit no hazardous characteristics under the RCRA criteria, thus are *Nonexempt Non-Hazardous*.

Nonexempt Special Waste: Wastes which are specifically identified and controlled under separate statutes and regulations--either on a state or federal basis. These wastes are usually handled separately under the federal and state regulatory programs due to their uniquely unsafe nature.

Example of Nonexempt Special Waste: Both PCBs and asbestos are unique wastes which warrant special handling and disposal dictated by separate statutes and regulation, thus are *Nonexempt Special Wastes*.

The API/EGD fully describes the regulatory basis for the above classification system as well as lists specific wasted defined as *Exempt* or *Nonexempt* by EPA.

Step 4. Identify All Management Options for Specific Waste

For each waste identified and categorized, all possible management practices potentially available for that waste should be listed. Within the context of the Plan, "waste management" includes:

- Minimization: Methods which minimize or reduce waste's volume and/or risk of doing harm to people or the environment.
- Handling: Practices associated with waste from the point of generation to the point of disposal. Handling includes storage, transportation, recordkeeping, waste sampling and analysis, and use of contracted waste handlers.
- Disposal: Methods and locations associated with on-site and off-site disposal or recycling of the waste, including use of public or private disposal locations.

Derive the list of management options from the following:

- Practices used for the waste in the Area
- Practices used for the waste in other Areas
- Practices used for other types of wastes
- Practices used by other companies or industries for similar wastes

The practices listed for the waste must be consistent with the waste's category. This means only practices which comply with the various regulations applicable to the waste's category in the Area should be listed. Waste categories are particularly important when considering mixing of several waste streams for storage, handling or disposal.

This step is a brainstorming exercise meant to identify potential practices. In this step, the listing of a particular practice or idea should not be biased by its practicality, availability or lack of historical use in the Area. It is important for the environmental engineer to identify possible new practices by transferring ideas and technology from other industries or geographic areas.

Example of "brainstorming" options - for BS&W in SE New Mexico:

Minimization

1. Change oil treatment process to reduce or change character of BS&W.
2. Allow more BS&W to be sold in production stream by lowering quality standard of product.

Handling

1. Drain BS&W from vessels into temporary earthen pits.
2. Use a vacuum truck to pump BS&W out of vessels.
3. Use liners, drip pans or catchment basins to minimize BS&W spillage.
4. Use contracted labor specialized in BS&W clean out of vessels.
5. Use company employees for BS&W clean out.
6. Use rigid containers with no leaks to store BS&W during handling.

Disposal

1. Spread/Disk in on lease road (with agency approval).
2. Haul by commercial oil reclaimer, who reclaims BS&W partially and disposes remainder in industrial landfill.
3. Landfarm (with agency approval)
4. Bury onsite (with agency approval)
5. Haul to centralized treatment disposal facility operated by company.
6. Keep records related to the disposal of BS&W.

Step 5: Select Acceptable Management Practices

From those listed in Step 4, practices deemed acceptable by applicable regulatory and company standards in the specific Area are chosen. The criteria used to deem a practice acceptable are:

- Acceptable under applicable waste regulation for the Area
- Acceptable under company environmental policy

Company policy dictates that besides being in regulatory compliance, practices must minimize the environmental impact and/or potential long-term environmental liability where possible.

Example: Of the management options listed in Step 4. for BS&W associated with Southeast New Mexico Operations, only the following were selected:

Minimization: None acceptable. No other treatment processes are available to reduce volume or nature of BS&W. Neither Company policy nor the state oil and gas regulations will allow product quality standard lower than the one currently used in the area.

Handling: All handling methods listed in Step 4. are acceptable except Option 1. Company policy calls for minimizing the use of earthen pits for wastes, even when allowed by regulation.

Disposal: Hauling to a commercial reclaimer or disposing at a Company-operated site (Options 2 and 5) are allowed by the agency.

Step 6: Prioritize Selected Management Practices

In most cases, more than one option will remain available after the selection process in Step 5. Three factors to consider in prioritizing the remaining minimization, handling, and disposal practices are <u>practicality</u> for the field operations, <u>availability</u> of options with specific area, and <u>cost</u> of options. Some acceptable options may even be eliminated from further consideration due to availability, practicality, or cost. A simple scheme of deeming the first priority option as "Preferred" and all others "Acceptable" is utilized.

Example: The options selected in Step 5 for BS&W in the Southeast New Mexico Plan were prioritized as below:

Minimization - None

Handling

Preferred Option - Use contracted labor specialized in BS&W clean-outs. Vacuum trucks to pump BS&W and appropriate use of drip catching liners to

minimize BS&W spillage is also specified for use by the contractor.
Acceptable Option - Use company employees for BS&W clean-out when contractor not available.

Disposal

Preferred Option - Haul to commercial oil reclaimer.
Acceptable Option - None. Use of a Company operated oil reclaimer is not currently available, nor practical or economical to operate.

The majority of an Area's Waste Management Plan is complete upon performing this six-step management selection exercise for each waste generated in the area. Though this process may appear protracted as presented here, it may be completed quickly with environmental and operations personnel working closely. Additionally, similar wastes occurring across Areas make development of subsequent Areas' Plans easier.

Writing the Plan's Document

For the collection of management guidelines for an Area's wastes to be most useful, communicating them effectively to the Operations personnel generating the wastes is essential. Attention must be given not only to the content of those guidelines but also the format in which those guidelines are presented.

1. Target Plan Toward Field Supervisor

With Operations personnel providing input to the six-step management option selection exercise, the Plan's document should be substantively practical and useful to Operations. Yet, for the document to be accepted and truly functional, it must be written in a style and format which is desired by the primary user group - field operations personnel.

More specifically, the primary users of the document are the first and second line production and drilling supervisors. These supervisors are often the focal point for implementing new policies and requirements generated by management and engineering personnel in the Company. It is important that they are provided clear, concise directives on what is required of their operation. This includes appropriate background and details without diluting the primary intent of the guidance. Other users of the Plan document are engineers, management, environmental professionals, and field personnel.

2. Plan's Format

To provide a concise, straight forward directive, as well as an appropriate amount of detail in the Plan document, a two-tiered format was used. This entailed having an encapsulated version of the Plan--called the One Page Summary, backed up by the full document.

The One Page Summary serves several purposes. It acts as a quick reference guide for all users. More importantly, it provides a comprehensive summary of the Plan on one page, which makes waste management guidance directly available to field personnel who normally would not read a technical manual. This One Page Summary may be incorporated in a plant operator's or pumper's field book or posted on a plant or field office bulletin board.

Appendix A shows the One Page Summary for Southeast New Mexico Production Operations. Appendix B describes the full document's basic structure and content. Appendix C gives an example of one waste's Handling and Disposal guidelines from the Plan.

3. Document Production Details

Many documents or manuals produced by a company to relay details on a technical

subject to its employees are ineffective because they are written and maintained by a detached staff group within the company. Often these manuals are not presented in a "user-friendly" format. To avoid some of the pitfalls of a Company Manual, the following were employed in producing and maintaining the Plan:

- Written and maintained by an environmental engineer who is familiar with and works with field operations routine.
- Significant opportunity for Operations to provide input into the Plan's publication and maintenance by the use of frequent and sometimes informal update/revisions.
- Use full power, personal computer-based word processor to write and maintain the Plan. This affords a high quality document while allowing quick revisions of the Plan.

Implementation and Maintenance of Plan

Once written, several critical steps remain for the Area Waste Management Plan to be implemented for use by Operations. Final approval and endorsement of the Plan must be received to ensure its use by the line personnel including:

1. Final review and comment from specific operations supervisory personnel who will use the Plan;
2. Review and approval by Legal Counsel; and
3. Review and endorsement by management

In maintaining the Plan, the local environmental engineer or staff (i.e. group working directly with Operations) should maintain control. Informal, minor revisions requested by Operations should be incorporated to allow the Plan to remain practical and dynamic. Revisions should also be made as regulatory or policy changes occur.

Formal reviews should occur periodically (biannually is suggested) to ensure all guidelines remain consistent with current regulations, technology and environmental science. The intent of the subsequent periodic reviews and updates is more than ensuring compliance. New and innovative minimization, handling and disposal strategies should be formally reviewed through the six-step process used to enhance the original Plan.

Although the examples presented in this paper are for Production operations only, the Plan's concepts have been similarly applied to Drilling and Gas Plant operations.

CONCLUSIONS

The development, implementation, and maintenance of the Area Waste Management Plan concept improves the Company's waste management by satisfying the stated needs as follows:

1. Improved understanding of wastes and waste management requirements and options was accomplished by listing and categorizing an Area's wastes, then listing available management options based on those categories.

2. Waste management goals and performance standards were established by use of the Plan's six-step development process to select and prioritize appropriate management options.

3. Communication and implementation of the established waste management goals and standards were improved by the writing and implementing of the Area Waste Management Plan document, as described, for the field operations.

ALTERNATIVE APPLICATIONS OF PLAN CONCEPT

This Area Waste Management Plan concept employs basic principles in identifying wastes and appropriate waste management practices based on an individual company's needs. The same concept can easily be applied on a broader scale.

Multiple Company Plans

One application is a collection of oil and gas companies combining efforts to develop and use a Waste Management Plan for all their operations in a defined area. The Plan's development process would not have to be altered significantly. There may also be added benefit in having the companies identify common problems and assist one another in solving those problems, either individual or collectively. One example extending from a multiple company Plan is possible establishing waste disposal sites cooperatively used and maintained by the companies involved.

Industry/Government Plan

A second possible application to the Area Waste Management Plan concept would involve a cooperative effort between private industry and the regulatory agency. Having the two entities working together would facilitate an increased awareness of the respective group's needs and goals. Using the Plan concept could avoid certain pitfalls in the regulatory process, and halt the trend of increasingly specific waste regulation.

ACKNOWLEDGEMENTS

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TABLE 1
Process for Development of Waste Management Strategies

STEP 1: Identify Area of Coverage

Define Areas similar in:
- Regulations
- Geology
- Environment
- Operations

STEP 2: Identify Wastes in Area's Operations

List all solid, semi-solid, & liquid wastes generated from the processes in Area's operation

STEP 3: Categorize Each Waste

Categories:
- *Exempt*
- *Nonexempt Non-Hazardous*
- *Nonexempt Hazardous*
- *Nonexempt Special*

STEP 4: Identify All Minimization, Handling, Disposal Options for Each Waste

"Brainstorm" to list all possible options for minimizing, handling and disposing each waste. Include management practices used for the waste in other Areas of Company and in other Companies or industries, and practices used for other wastes, as well as practices currently used in the Area.

STEP 5: Select Acceptable Management Practices

All options selected must be acceptable under applicable regulations and Company policies
- i.e., must be environmentally sound by Company and government standards

STEP 6: Prioritize Remaining Options

- Prioritize as "Preferred" or "Acceptable".
- Base priority on policy, practicality, and cost.
- Practice may also be eliminated based on practicality or cost.

TABLE 2
Wastes generated by production operations in SE New Mexico

Production Wastes

Refuse	Contaminated Soil	Slop Oil
Produced Water	Solvents	Paraffin
Used Lube Oil	Empty Drums	Surplus Chemicals
Tank Bottoms, BS&W	Methanol	Used Acid Batteries
Oil and Water Filters		

Completion & Workover Wastes

Well Completion, Treatment & Workover Fluids
Miscellaneous Rig Wastes

Special Wastes

Asbestos	Pesticide Waste	PCBs
Pesticide Waste	Trichloroethylene	

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APPENDIX

APPENDIX A	One Page Summary of Area Waste Management Plan for Southeast New Mexico Production Operations
APPENDIX B	Basic Format and Content of Full Area Waste Management Plan
APPENDIX C	Example of Handling and Disposal Guideline for One Waste

WASTE MANAGEMENT PLAN

One Page Summary
4/90

Southeast New Mexico
ARCO Oil & Gas Company

WASTE	SEC.	HANDLING & DISPOSAL GUIDELINES
		PRODUCTION WASTES
REFUSE,PAPER,TRASH	2.1.1	• Use trash containers, no pits. Dispose using local trash contractor or directly with municipal landfill
PRODUCED WATER	2.1.2	• Reinject into ARCO wells or dispose using a water hauler listed on the Hobbs office's approved bid list
USED OIL	2.1.3	• Recycle to production stream, or sell to approved oil relaimer*.
OIL & WATER FILTERS	2.1.4	• Drain fluids back to production. Dispose dry filter with trash at approved municipal landfill
TANK BOTTOMS, BS&W	2.1.5	• Reclaim using approved tank cleaner*.
SLOP OIL	2.1.6	• Reclaim* or add to crude production
"HOT OIL" PARAFFIN	2.1.7	• Circulate hot fluid/paraffin back to production stream
CONTAMINATED SOIL	2.1.8	• For oil or water spills, remove free liquids, disk in or bury, stained soil. For spills of certain chemicals or if required by the agency, remove soil and haul to an approved disposer*.
SOLVENTS	2.1.9	• Use approved solvent recycler*, or call Env. Rep.
EMPTY DRUMS	2.1.10	• Be sure drum is empty of all free liquids. Through Materials Rep.: 1. be sure bungs are in; 2. return to vendor; 3. use approved commercial drum disposer.
SURPLUS CHEMICAL	2.1.11	• Through Materials Rep.: 1. find a use for it at another ARCO facility; 2. return to vendor; or 3. call Environmental Rep.
METHANOL	2.1.12	• For de-icing or testing lines, circulate back to production stream.
USED ACID BATTERIES	2.1.13	• When buying new battery, have dealer retain battery when changed out. Store or transport no more than 3 used batteries at a time.
		COMPLETION & WORKOVER WASTES
WORKOVER & WELL TREATMENT FLUIDS	2.2.1	• Use lined pits. Vacuum fluids out and dispose at approved commercial facility*, or circulate back to production with Production's approval.
MISCELL. RIG WASTES buckets, empty sacks, used filters, quarters trash	2.2.2	• Do not store or dispose in reserve or other pit. Use all material dope before disposing of empty containers. Store in a dumpster and dispose at authorized landfill.

***SPECIAL WASTES*: PCBs, ASBESTOS, PESTICIDES, NORM, TRICHLOROETHYLENE (Sec. 2.3)**
If these wastes, or material suspected to contain these wastes, are found, notify your Supervisor or Environmental Rep. for handling and disposal.

****

GENERAL NOTES

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1. * Reclaim oily wastes using contractors and disposal locations listed on the back of this Summary or in Section 3.2 (*Waste Handlers and Disposal Sites*) of the full Area Waste Management Plan.
2. SEC column shows the Section of the complete Waste Management Plan. For more detail on these and other waste guidelines, refer to the complete Plan or call the Environmental Department (915-688-5560).
3. If unidentified material or waste is found at an ARCO facility, contact your Supervisor or Environmental Rep. for assistance in identifying and handling.
4. If illegal disposal by a contractor is seen or suspected, contact your supervisor.
5. Waste disposal into pits is no longer acceptable. All pits are permitted for only specific uses; know these uses.

APPENDIX B

Basic Format and Content of Full Area Waste Management Plan

Inside Cover One Page Summary

Section I Introduction

- Brief background and description of Plan including definition of waste categories

Section II Handling and Disposal Guidelines - By Waste

- Guidelines presented on a waste-by-waste basis, including a brief description of the waste and its source, its waste category, and a listing of "Acceptable" and "Preferred" management practices.
- Handling practices cover waste minimization, waste storage, testing/analysis and requirement where appropriate.
- Disposal practices include waste transportation, types of disposal methods, appropriate record to keep, and specific disposal locations and companies to use.
- To facilitate locating wastes in the plan, wastes are grouped by the operation from which they are generated:

1. Production Operations - Wastes are grouped as follows:

   Production Wastes - wastes from routine field production operations
   Workover/Completion Wastes - wastes from well work handled by the Production Department
   Special Wastes - for non-routine or unexpected wastes, such as PCB's or asbestos).

2. Drilling Operations - Wastes are grouped as follows:

   Drilling Wastes - for waste generated from operations associated with a drilling rig
   Workover/Completion Wastes - for waste generated from operations associated with a pulling unit or completion rig
   Non-Rig Operations Wastes - for wastes from operations not requiring a rig such as wireline work
   Special Wastes - as addressed in the Production section above

3. Gas Plant Operations - Wastes are grouped only as Gas Plant Wastes and Special Wastes.

Section III: District/Company Waste Management Policies and Practices

- Relevant Company or District policies or guidelines related to waste management are included.
- Such general policies or guidelines may include: Hazardous Waste Handling and Disposal, Identification and Handling of Unidentified Materials, and Selection of Waste Contractors.

Appendix: Summary of APE Guidance or Onshore Solid Waste Management in Exploration and Production Operations

- This is included for the plan's users and reviewers because the plan is heavily reliant on the API/EGD as a reference for regulatory, technical and environmental information regarding oil field waste management.

2.1.5 TANK BOTTOMS AND BS&W

Tank bottoms or BS&W (basic sediment and water) is an oil field term referring to solid and emulsified waste that settle out of crude oil into tanks and process vessels. BS&W is normally a liquid heavily laden with solids and often entrained with produced water.

Category: *Exempt Waste*

Handling and Disposal

1. Preferred Handling and Disposal - An approved tank cleaner or hauler* should be used to remove and transport BS&W. Contractors handling BS&W should be disposing of the non-saleable fractions at a facility approved to accept such material* (i.e., permitted by NMOCD).

2. Acceptable Handling - If/when an approved tank cleaner is not available, company personnel may be used to remove and store the BS&W. Disposal at an approved disposer* is still required.

3. Removal of BS&W from the vessels should be done in a manner where no spillage occurs. Use of drip pans, plastic liners or catchment vessels are recommended to ensure this.

4. If BS&W has to be stored, rigid containers are preferred. BS&W should never be stored in (even temporarily) in lined pits.

5. Records related to the disposal of BS&W should be retained for at least three years, including:

   Date of shipment
   Hauler's name and approval number
   Disposer's name and approval number
   Source/location of origin
   Volume of load

* **See Section 3.2 for a list of currently approved waste disposers and the process of selecting waste contractor. If a list is not available, check with the Area Production Superintendent.**

THE ATTENUATION OF THE AQUIFER CONTAMINATION IN AN OIL REFINERY STABILIZATION POND

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Abstract

The infiltration of oil derivative organic compounds in the underground water in a refinery stabilization pond can be reduced by lining it with a sodium bentonite modified by the tetramethylammonium cation. Wyoming bentonite as well as a Brazilian bentonite were tested in the present study. The hydrophobic nature of this ammonium quaternary cation makes yhe silica-alumina surface of the clay more receptive to organic molecules and, above all, to polar organic molecules. Some organic compounds typical of the oil industry waste waters were tested at temperatures close to the ambient. Isotherms were plotted and their shapes were compared with Freundlich isotherms. The correlation coefficients found for all isotherms were close to 0.9 showing that the Freudlich isotherm is in good agreement with the results of this adsorption study. Adsorption is higher at lower temperatures meaning that in the winter underground contamination tends to be smaller.The adsorption of phenol at 1,000 ppm and 20^{o}C has shown a removal effectiveness of 85%. For lower concentrations and higher temperatures the adsorption was less effective. The linear nonpolar organic molecules had shown a lower adsorption pattern.

Introduction

Stabilization ponds are economical devices to treat liquid effluents of the oil industry. If the soil where the pond is built is a sandy one then the infiltration of the waste water in the aquifer may poison the underground water.

The objective of this paper is to propose a lining mixture of regular soil and clay for oil refinery stabilization ponds which impermeabilize the pond and, at the same time, adsorb the organic pollutants present in the waste water. Strong attention will be devoted to phenol because of its high toxicity (40 mg/l) as compared with the other pollutants present in the waste and because of its polar nature which makes it likely to be easily adsorbed by organophilic bentonites. These bentonites are clays modified by the substitution of the interlayer sodium cation by a quaternary ammonium cation. Sodium bentonites are very impermeable. The quaternary ammonium cation derivatives are organophilic but not impermeable. Therefore the lining of the pond must be prepared with a mixture of regular soil (as filling), sodium bentonite and the organo clay. Several quaternary ammonium cations are available for purchase. The tetramethylammonium cation is very effective to adsorb most organic molecules. But because of its high cost the preference is towards the tallow oil derivatives. This is the so called fatty ammonium quaternary cation. The resulting cation has three nytrogen bonds replaced by methyl groups and the remaining fourth bond is replaced alternatively by linear saturated radicals with 12, 16 and 18 carbon atoms. These are radicals derived from the palmitic, oleic and fumaric fatty acids.

Literature Review

The hydrophilic nature of sodium bentonites makes them a poor adsorbant for organic molecules (4). Therefore other cations besides sodium were tested to improve the organophilic properties of these clays. The first trial was to replace sodium by the most simple ammonium cation, i. e., tetramethyl ammonium cation (1). Sodium bentonites swell very easily in water and it can expand up to 15 times its original volume. This means that the small clay particles (2 μm in size) tend to defloculate in water and these swelling and defloculating properties make them a powerful impermeabilizing agent to be used in dams and reservoirs (2).

The bentonite modified by a quaternary ammonium cation can become a better adsorbant for organic molecules (5). The proposed explanation is that the hydrophobic nature of the cation makes the clay surface more receptive to organic molecules. The presence of organic groups bonded to the nitrogen atom in the space between the layers of silica and alumina in the structure of the clay is responsible for the solubilization of the organics and its later adsorption. The tetramethylammonium bentonite is very effective in the adsorption of organics but other quaternary ammonium cations, in spite of being less effective, can also be used (3).

Materials and Methods

Four different organo clays were used in this series of experiments: two derived from Wyoming bentonite and two derived from a Brazilian bentonite.The quaternary ammonium cations used were tetramethylammonium and a cation derived from hydrogenated fatty acids.

The Brazilian bentonite has originally calcium cations between the layers of silica and alumina of the clay mineral structure. Therefore it has to be modified with sodium carbonate in order to become a sodium bentonite.

The Wyoming bentonite is a sodium bentonite with a high content of the clay mineral smectite (90%). The purity of the Brazilian bentonite is lower than that (70%).

Method to Modify the Sodium Bentonite

The sodium bentonite is suspended in an aqueous solution of the quaternary ammonium chloride for 24 hours under agitation. After centrifugation the bentonite is washed with water until no free chloride is present (test with silver nitrate). The modified bentonite is then dried at 60°C and after that ground into a fine powder.

Method to Measure the Adsorption of Organics on the Surface of the Clay

The concentration of the organics in solution is measured by the TOC (Total Organic Carbon) method using sodium persulphate as an oxidizing agent. The carbonic gas concentration generated by the oxidation of the organic matter is measured through infrared spectrometry.

Results and Discussion

Results are shown on Figures 1 and 2. The adsorption of phenol on Wyoming bentonite exchanged with tetramethylammonium cation is the most effective. Evidence of this fact was already shown in the literature (5) when several adsorbants were tested with an aqueous solution of phenol. The present experiments show that the isotherms at 20°C are in good agreement with the Freudlich isotherm. The correlation coefficients are in the vicinity of 0.9. The polar nature of the phenol molecule makes its adsorption more effective than that of the hydrocarbons tested. The tetramethylammonium derivative is better than the fatty acids derivative used but the cost makes this last one more competitive.

Wyoming bentonite derivatives give better results than the Brazilian bentonite because of its higher content of the clay mineral smectite.

Conclusions

A mixture of regular soil, sodium bentonite and a bentonite modified by a quaternary ammonium cation derived from hydrogenated fatty acids can be used as a liner in a refinery stabilization pond both as a sealing agent and also to attenuate the infiltration of organic pollutants in the aquifer.

Acknowledgements

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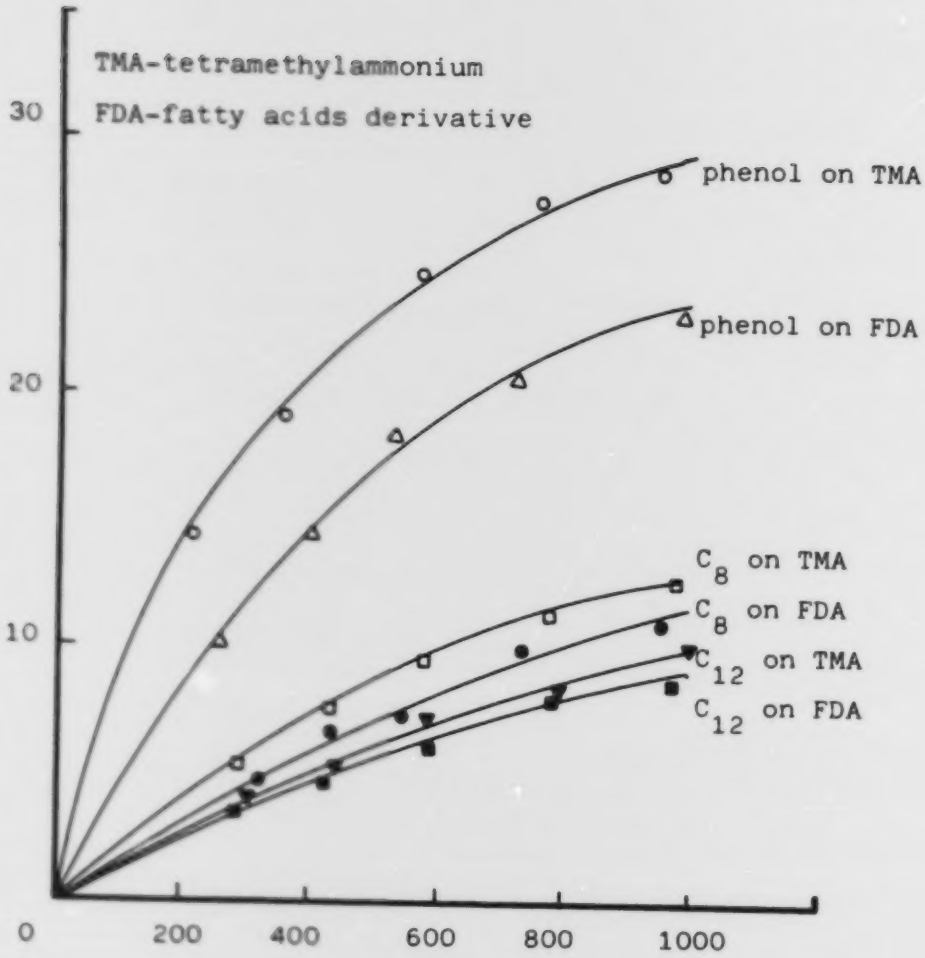

Figure 1 Adsorption of some pollutants from oil refineries waste waters on Wyoming bentonite modified by quaternary ammonium cations.

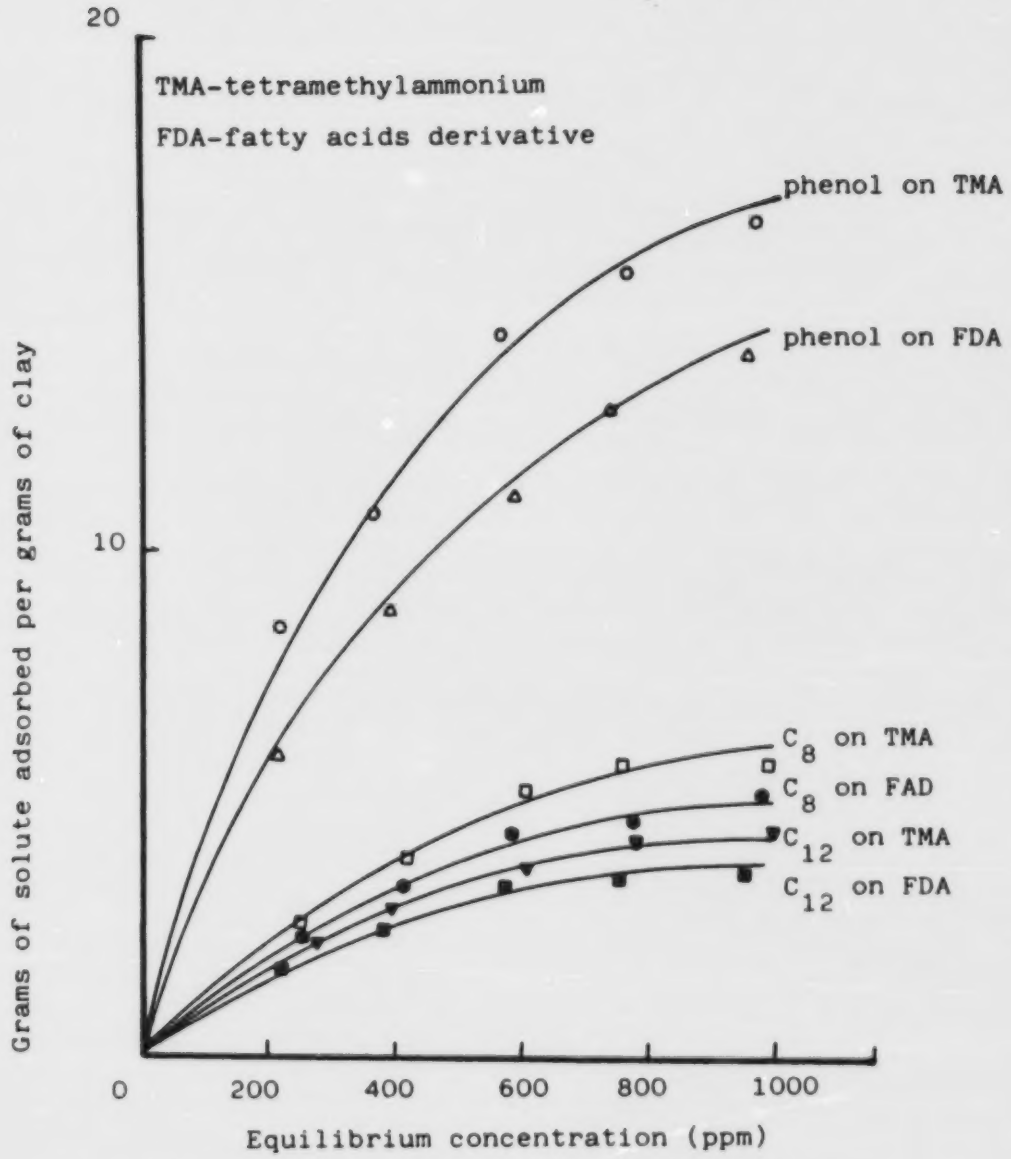

Figure 2 Adsorption of some pollutants from oil refineries waste waters on a Brazilian bentonite modified by quaternary ammonium cations.

BP SUPERWETTER - AN OFF-SHORE SOLUTION TO THE CUTTINGS CLEANING PROBLEM

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INTRODUCTION.

Drilling with oil based mud (OBM) provides many technical and economic advantages, and can be virtually essential for some geological formations. However extensive studies, especially in and around Europe have shown that areas of the sea bed, where oily cuttings have accumulated from OBM drilling operations, suffer marked physical, chemical and biological changes.

A ban on the discharge of oil contaminated cuttings has been in operation in the USA for several years. However existing legislation in Europe affecting operations in the North Sea permits a controlled discharge of oily cuttings waste. In Norway and Holland the level of discharged oil, averaged over the well sections drilled with OBM, must not exceed 100g for every kg of dry cuttings residue, (10%w/w). In the United Kingdom North Sea the allowable discharge limit is 150g/kg, (15%w/w).

Cuttings cleaning procedures generally follow one of two main regimes.

i) Base Oil Wash:
Oily cuttings are slurried into low toxicity base oil before being pumped through a combination of low and high speed decanting centrifuges which achieve the solid-liquid separation. Cuttings discharges from the centrifuges are flushed into the sea and the recovered fluids are recycled around the cleaning system.

ii) Surfactant Wash:
Oily cuttings are mixed into an aqueous surfactant solution by means of a rotating washdrum where the majority of the cuttings are removed from the cleaning solution by feeding the mixture over a shaker. Cuttings separated by the shaker are discharged overboard and the fines / oil / surfactant solution, are further processed through a combination of decanting and disc-stack centrifuges to effect separation. The cleaning solution is recycled around the hardware.

Each of these systems is shown diagrammatically in Figs. 1 and 2.

In the near future oil on cuttings discharge limits are going to be reduced. Whereas the systems available now can meet the 10%w/w requirement, they are not capable of meeting any limit set significantly lower than this. Over the next year new legislation will be implemented in Norway and within 2-3 years is is almost inevitable that Holland and the UK will also reduce the allowable discharge of OBM.
A research project within British Petroleum has looked at this problem and developed a novel type of cleaner, which is operational in an off-shore environment, to substantially reduce the retained oil on drill cuttings. It is the development and testing of this cleaner that is described below.

Novel Cleaner Concept.

The cleaning fluid works neither as a solvent nor an emulsifier but by displacement. The cleaner preferentially wets the surface of an oil contaminated cutting, displaces the oil and since the cleaner does not mix with or emulsify oil the two liquid phases separate. Oil, having the lower density, forms the upper phase which can be 'decanted' off and the lower phase cleaning fluid is recovered and recycled.

EXPERIMENTAL.

The test results of two cleaning formulations, coded K5T and CJD40 respectively are described here. The test work is in three stages;

i) Laboratory evaluation
ii) Pilot scale studies
iii) Full scale off-shore tests

i) Laboratory Evaluation.
The evaluation technique used in the laboratory utilised simple controlled mixing of cuttings and cleaner followed by filtration. Several types of oily cuttings were used in the laboratory tests ranging in geology, type of drilling mud and degree of contamination. In all cases, the mud oil component was BP 83HF as supplied by BP Chemicals. The cuttings samples were from a number of BP North Sea and UK land based operations. The cuttings tended to be small (from the 8.5" and 6" well sections), and were therefore, ca.<5mm in size.

Cuttings were mixed with the cleaner in ratios of 1:5 to 1:2 prior to filtration, and in some instances a further washing stage using sea-water. The cleaned cuttings were collected and measured for residual oil content. The collected recovered fluids separated into two phases, cleaner and oil. The cleaner could then be used again to treat further oily cuttings and the composition of both phases could be analysed.
Comparison cleaning experiments were carried out using a 5%v/v solution of a commercial surfactant ('By-Prox',ex BP) and low toxicity base oil (BP83HF, ex BP) as cleaning media.

A number of drying experiments were carried out on some of the cleaned cuttings to assess the efficiency of low temperature thermal techniques for removing residual cleaner from the treated rock cuttings. Several samples of cuttings were simultaneously weighed into glass laboratory petri-dishes and placed in an oven at either 140°C or 180°C (284 or 356°F). After 1, 6, and 16 hours of being in the oven individual samples were removed and their oil, cleaner and total moisture contents determined.

The analytical techniques used are described at the end of this section.

ii) Pilot Scale Studies.

Two different types of hardware were used in the pilot scale test work. The first was based around a decanting centrifuge performing the majority of the solid-liquid separation and in the second, the largest proportion of the cuttings were separated from the cleaner on a shaker screen. These are shown schematically in Figs. 3 and 4. The hardware was supplied and set up on behalf of BP by Thomas Broadbent and Sons Ltd (TB&S) at their laboratory facilities in Huddersfield, England.

The cuttings used in these studies were obtained from several drilling locations and as such provided a variety of geologies and mud types. Pipework restrictions meant that the cuttings needed to be 10mm or less and were therefore sourced from the 8.5", 6" or lower 12.25" well sections.

Using the decanting centrifuge apparatus (Fig.3), cuttings were mixed with the cleaner to a slurry concentration of 30%v/v and kept in suspension using a mechanical stirrer. After mixing for 3 mins,the slurry was pumped to the laboratory decanting centrifuge.This centrifuge was a 150mm x 300mm heavy duty horizontal solid bowl decanter centrifuge, working at 2450rpm (510G). The slurry was pumped at a flow rate of 11-12 l/min and samples of produced cake and recovered fluids were taken for analysis.

Experiments using the shaker screen apparatus (Fig.4), cuttings were mixed with the cleaner to a concentration of 30-40%w/w and the cuttings were held in suspension in a specially designed mix tank with a low shear agitator. This mix tank was located directly above the leading edge of the shaker screen. The screen itself was a modified full size oil-field shale shaker. The majority of the shaker was blanked off to leave a channel 300mm wide running the full length of the shaker. The cuttings, having been contacted with the cleaner for a fixed time (usually 2mins) were fed directly from the mix tank onto the shaker where they were transported down the channel.
Samples of cuttings were taken from the shaker for oil-on-cuttings analysis. The underflow from the shaker, which consisted of fines, cleaner and oil was further separated through decanter (4000rpm, 1350 x g) and disc bowl (10,500rpm, 4000 x g) centrifuges. Samples of the separated fines and each of the liquid phases were collected.

iii) Full Scale Off-Shore Tests.

A limited amount of test work has been completed on two BP drilling sites in the Norwegian sector of the North Sea. This test work used both types of existing cuttings cleaning hardware ie;

- a combination of decanting centrifuges
- a washdrum type system

(see Figs. 1 and 2 for schematics of these types of systems).

These tests were carried out with permission from the Norwegian State Pollution Control Authority and cooperatively with BP Norway, Thomas Broadbent and Sons Ltd. and Swaco Geolograph (Aberdeen, Scotland).

In each case the cleaner was used in the existing hardware as a direct substitute for either low toxicity base oil or surfactant solution, no modifications were made to optimise the cleaner/hardware combination. Throughout several short trials oily cuttings from the 12.25, 8.5 and 6" well sections were treated. Cuttings were processed through the hardware and samples were taken for analysis at each solids discharge point. In the decanting centrifuge set-up this meant collecting samples from the primary and secondary decanters. From the wash-drum system, samples of cleaned cuttings and fine solids were collected from the shaker screen, the decanting centrifuge and the disc stack centrifuge. Recovered fluids were also collected for analysis, ie. both cleaner and separated oil.

ANALYTICAL TECHNIQUES.

Oil-on-Cuttings analyses were carried out using a standard mud retort. The volume of oil collected is converted to weight and results were expressed as %w/w oil on dry cuttings residue. Levels of residual cleaner and total moisture of the cuttings were measured by converting each of the fluid phases condensed by the retort to weights and totalling these weights to express the results as %w/w on cutting as discharged. The mass balance on each of the mud retort experiments was checked and agreement within 2% was considered acceptable for the data to be used.

Chemical Analysis of the recovered oil and cleaner phases from the cuttings cleaning experiments was conducted using a laboratory gas chromatograph.

RESULTS.

i) Laboratory Experiments.

Table 1 sets out cuttings cleaning data obtained in the laboratory using both the K5T and CJD40 cleaners. In Table 1a the results show that a low toxicity base oil wash and a surfactant wash reduce oil-on-cuttings from 18.7%w/w to 12.6% and 13.2% respectively. Under the same experimental conditions, K5T reduced the oil-on-cuttings to 2.3%w/w.

Removing the water wash stage from the laboratory experiments did not significantly affect the de-oiling efficiency of K5T. Table 1b shows a reduction in oil content of cuttings contaminated with 'all-oil' drilling mud from 27%w/w to 7.5-10%w/w. K5T performed slightly better on cuttings contaminated with an 80:20 drilling mud, reducing oil-on-cuttings from 21.1% to 3.3-5.8%w/w.
Cleaner CJD40 reduced the level of oil-on-cuttings in lab tests from 14.3%w/w to 5.1-6.1%w/w. These results are shown in Table 1c.

Cuttings which had been treated in deoiling experiments by either K5T or CJD40, were 'dried' at 140 or 180°C. As the results in Table 2 show show, significant reductions in cuttings moisture content could be achieved in relatively short times using these low temperatures. At 140°c cuttings treated using K5T reduced from 29.1%w/w total moisture to just 5.4%. Concurrently the level of oil on the cuttings reduced from 9.8% to 2.0%w/w. Total moisture includes residual oil, cleaner and water. After 3 and 6 hours total moisture levels stood at 3-4%w/w and the residual oil remained constant at 1-2%w/w.
At 180°C, as expected, the cuttings dried more quickly and after 1 hour a total moisture content of 26.9%w/w had been reduced to 2.2%w/w. Again there was an associated reduction in the oil content of the cuttings, from 9.6% to 1.0%w/w. After 6 hours in an oven test at 180°C, the residual oil-on-cuttings had fallen to a level which was so low as to be undetectable by retort analysis.
A similar phenomenon was observed from drying cuttings treated by CJD40 in an laboratory oven at 140°C. An initial moisture level of 23%w/w was reduced in 1 hour to 3.6%w/w. The oil-on-cuttings of the sample was relatively low prior to the 'drying' experiment at 3.4%w/w (sample collected from pilot scale studies), however this reduced further to 2.4% after a 1 hour thermal test and to 0.5-1%w/w after periods of >3 hours at 140°C.

ii) Pilot Scale Tests.
As stated earlier in the text, these tests were carried out on two types of hardware each of which carried out the primary solid/liquid separation stage in a fundamentally different way. The first used a decanting centrifuge to perform the separation (Fig.3) and the results of these experiments are shown in Table 3a. During these tests K5T was used as the cleaning medium. K5T reduced the residual oil level of cuttings having oil contents of 39%, 45%, and 18.6%w/w, to 4.2%, 5.2%, and 3.7%w/w respectively. Under identical experimental conditions, a low toxicity base oil wash reduced the oil content of these same cuttings to 12.5-14.4%w/w. The K5T cleaner,therefore removed 80-90% of the oil from the cuttings compared to an efficiency of 63-72% for base oil.

The second type of hardware used a shaker screen as the main solid/liquid separating method (Fig.4). Cuttings cleaning experiments were carried out using both the K5T and CJD40 cleaners. The detailed results of these tests are shown in Table 3b. After cleaning in K5T, oily cuttings from a 12.25" well section, with an initial oil content of 7.5%w/w, were reduced in oil content to 1.3-3.6%w/w. Similarly, cuttings from a 12.25" well section

with an initial oil content of 8.45% were cleaned with CJD40 to give cuttings containing only 1.4-3.0%w/w oil.

In both sets of experiments once the majority of the solids were removed from the system. The large solids are removed by the primary separation stage and the fine solids are flocculated by the cleaner so that the majority are removed by the secondary separation hardware. The cleaner and oil split into two separate layers allowing recovery of both.

iii) Full Scale Off-Shore Tests.

The initial off-shore test work reported here utilised the K5T cleaner in both types of existing cuttings cleaning hardware (ie. the decanting centrifuge system and the washdrum system shown in Figs.1 and 2).

In the decanting centrifuge system K5T reduced the oil-on-cuttings of a relatively contaminated feed containing 17.3%w/w oil to ca. 6.8%w/w (Table 4). This represents a cleaning efficiency of 61%. By comparison when the system was switched back to low toxicity base oil, the level of oil on cuttings was 13%w/w, representing a cleaning efficiency of 25%.

The same cleaning formulation was used in a wash-drum system. The results of this test are shown in Fig 5. Over an 800m section of a section of the 12.25" well K5T reduced the oil-on-cuttings to an average of 3-3.5%w/w with a best result of 2.5%. Throughout the trial the well was drilled at full rate (ie. 40-60m/hr) and all the cuttings were fed through the cleaning system. Oil and cleaner separation was achieved in the disc stack centrifuge so that the cleaner could be recycled to the cleaning system and the purity of the recovered oil was measured at >98%. The oil therefore was more than suitable for recycle back to the active mud system.

DISCUSSION

In laboratory, pilot and full scale experiments both K5T and CJD40 cleaners have been shown to provide superior deoiling of drill cuttings, to levels substantially below what is achievable with current technology. The full scale tests confirmed that, because of the enhanced surface activity of this type of cleaner, a less attritive hardware arrangement is preferable. The washdrum / shaker system (Fig 2) caused less breakdown of the cuttings than the decanting centrifuge system (Fig 1) and thereby reduced the level of fines which had to be separated, keeping the cleaner in better condition. In the light of these findings the project work is continuing to further optimise a hardware combination for this type of cleaner.

Residual cleaner on the cuttings can be efficiently removed using low temperature drying. It should be noted that the drying process described in this paper provides relatively inefficient heat transfer to the cuttings. In correctly engineered drying hardware it is anticipated that cuttings from the cleaning hardware could be dried on a continuous basis using steam as a heating medium for the process. This would provide cuttings for subsequent disposal containing <2-3%w/w oil and <5%w/w cleaner.

A small degree of cross contamination of cleaner into the recovered oil was noted during gas chromatography analysis. The levels of contamination were <10%,typically 2%w/w. Mud compatibility experiments in the laboratory where fresh and used muds were deliberately contaminated with up to 20% cleaner showed that even at this improbably high level of contamination the rheological properties of the mud were unaffected.
The K5T / CJD40 cleaned cuttings behaved differently to oily cuttings. The cleaning process left the cuttings 'water wet'. When these cuttings were dropped into water they broke up and dispersed easily. It is anticipated, therefore, that when the cuttings are discharged directly into the sea, they would disperse in a similar way to cuttings discharged from drilling operations using water based mud and would not form the localised cuttings pile observed as a result of oily cuttings discharge. Additionally, both these cleaners are water dispersible and any cleaner left on the cuttings when they were discharged would disperse into the upper layers of the water column where it would be available for aerobic biodegradation.
In terms of their physical properties, both cleaners are water white liquids. The flash point of K5T is 66°C (by ASTM D93) and CJD40 is >100°C. The density of these fluids is 0.96g/cm^3.

CONCLUSIONS

In order to reduce the environmental impact of oily cuttings and support the continued use of oil based mud in drilling operations, novel cleaning fluids have been developed which can substantially reduce the level of residual oil on cuttings.
The cleaners have been tested in laboratory, pilot scale and full scale equipment and the results show that cuttings can be reduced from >20%w/w to <2%w/w oil. A low temperature drying process can quickly reduce the total moisture hold-up of the cuttings (ie. oil, cleaner and water) from >20%w/w to less than 5%.
The cleaners have been formulated for off-shore use and produce cuttings which are 'water wet' and easily break up and disperse in a water column.
The development of a fully optimised hardware / fluid combination is continuing with the aim of producing cuttings for disposal containing <2-3%w/w oil and <5% cleaner. It is anticipated that the development will be complete by the end of 1990.

ACKNOWLEDGEMENTS

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We would like to acknowledge the staff at Thomas Broadbent and Sons Ltd, especially John Wright and Steven Howe and also staff from Swaco Geolograph, particularly Dave Simpson and Jim Hamill.

TABLE 1

LABORATORY CUTTINGS CLEANING EXPERIMENTS

a) Cleaning --> Water Wash --> Filtration

Cleaning Solution	%w/w oil on dry cuttings residue
* None	18.7
* None	17.6
5% Surfactant in Water	13.2
Base Oil	12.6
K5T	2.3
K5T	2.4

b) Cleaning --> Filtration

Cuttings Type	Cleaning Solution	%w/w oil on dry cuttings residue
(i) 'all-oil' mud	* None	27.0
	K5T	7.5
	K5T	8.5
	K5T	10.0
(ii) 80:20 mud	* None	21.1
	K5T	3.3
	K5T	3.3
	K5T	5.8
	K5T	4.2
	K5T	5.2
	K5T	3.6

c) Cleaning --> Filtration

Cleaning Solution	%w/w oil on dry cuttings residue
* None	14.3
CJD40	5.1
CJD40	5.9
CJD40	5.5
CJD40	6.1

TABLE 2

LABORATORY CUTTINGS DRYING EXPERIMENTS

a) Cuttings Cleaned Using K5T Cleaner

Oven Temperature (°c)	Time (hrs.)	Cuttings Analysis (%w/w oil)	(%w/w total moisture)
140	0	9.8	29.1
	1	2.0	5.4
	3	1.0	3.4
	6	2.0	4.1
180	0	9.6	26.9
	1	1.0	2.2
	6	(0)	2.4
	16	(0)	1.2

b) Cuttings Cleaned Using CJD40 Cleaner

Temperature (°c)	Time (hrs.)	Cuttings Analysis (%w/w oil)	(%w/w total moisture)
140	0	3.4	23
	0.5	2.6	4.0
	1	2.4	3.6
	3	0.7	2.2
	16	0.5	1.8
	24	0.5	1.8

TABLE 3

PILOT SCALE CUTTINGS CLEANING TRIALS

a) Decanting Centrifuge Apparatus

Initial Oil on Cuttings %w/w	Base Oil Wash		K5T Wash	
	Residual OOC %w/w	% oil removed	Residual OOC %w/w	% oil removed
39.0	14.4	63	4.2	89
45.0	12.5	72	5.2	88
18.6	-	-	3.7	80

b) Shaker Screen Apparatus

Initial Oil on Cuttings %w/w	Base Oil Wash		K5T Wash	
	Residual OOC %w/w	% oil removed	Residual OOC %w/w	% oil removed
7.5	3.9	48	2.6	65
			1.3	82
			2.3	69
			1.6	77
			1.8	76
			3.6	52

Initial Oil on Cuttings %w/w	Base Oil Wash		CJD40 Wash	
	Residual OOC %w/w	% oil removed	Residual OOC %w/w	% oil removed
8.45	-	-	3.02	64
			1.39	84
			2.47	71
			1.96	77
			2.67	68

TABLE 4

FULL SCALE OFF-SHORE CUTTINGS CLEANING TESTS

Initial Oil on Cuttings %w/w	Base Oil Wash		K5T Wash	
	Residual OOC %w/w	% oil removed	Residual OOC %w/w	% oil removed
17.3	13.0	24.8	6.8	61

FIGURE 1

A BASE OIL WASH IN A CENTRIFUGE-CUTTINGS CLEANING SYSTEM.

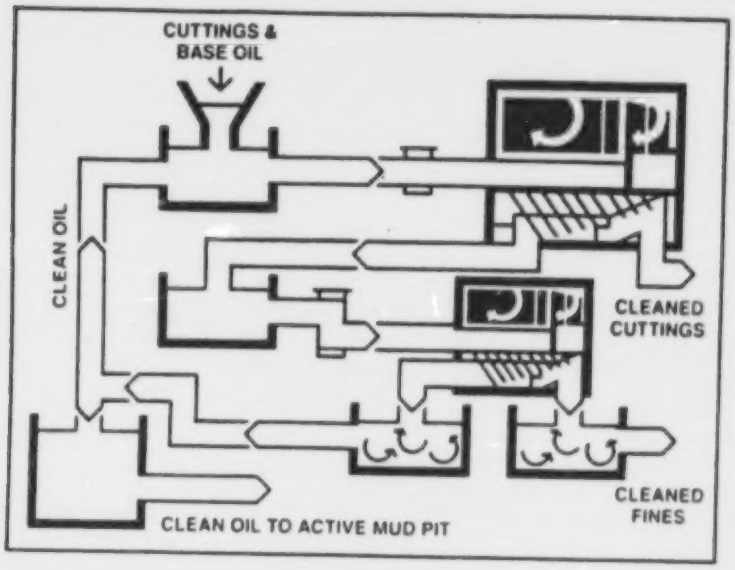
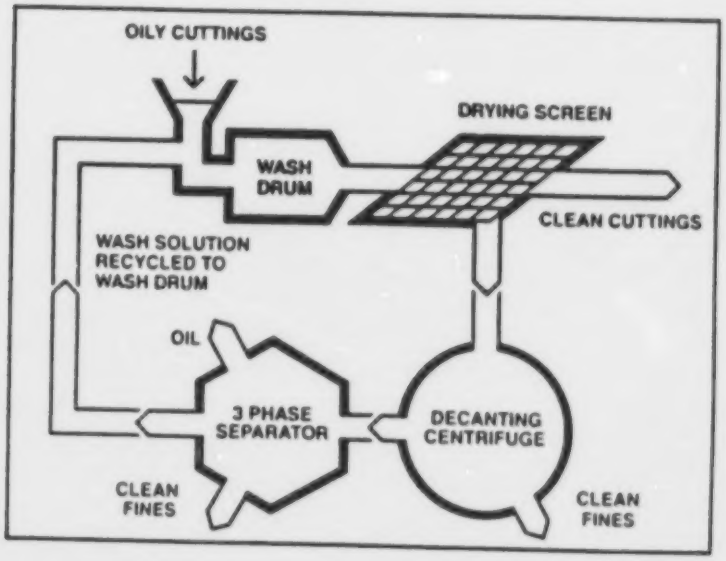


FIGURE 2

A SURFACTANT SOLUTION USED IN A WASH DRUM SYSTEM.



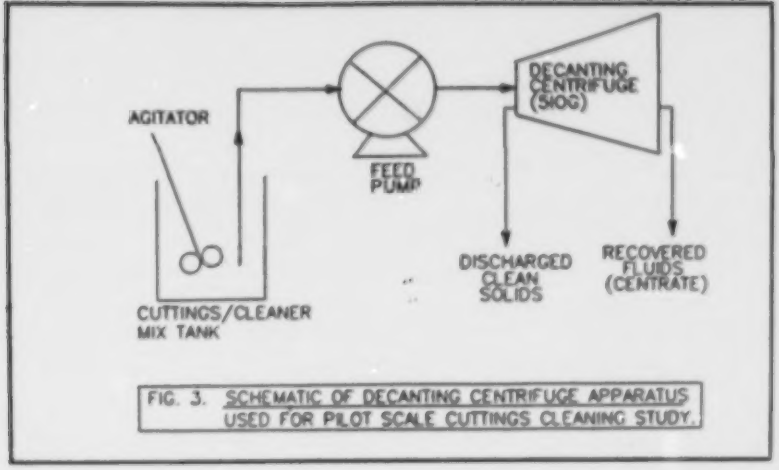


FIG. 3. SCHEMATIC OF DECANTING CENTRIFUGE APPARATUS USED FOR PILOT SCALE CUTTINGS CLEANING STUDY.

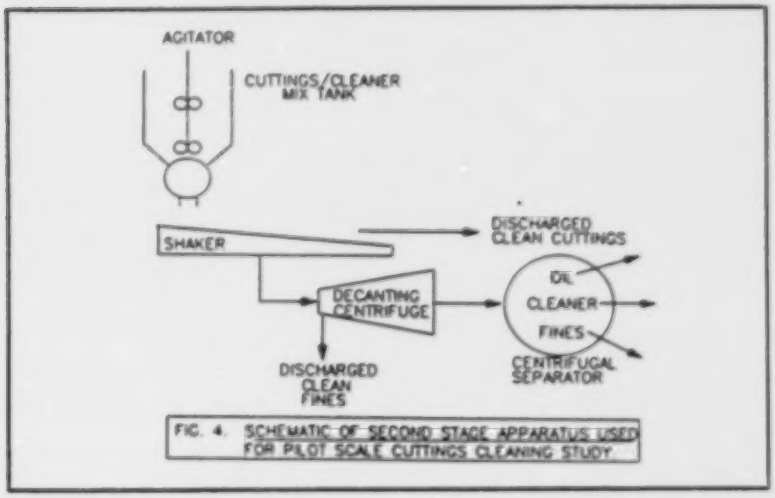
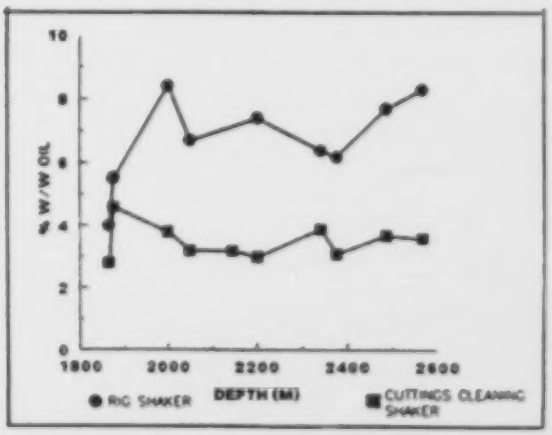


FIG. 4. SCHEMATIC OF SECOND STAGE APPARATUS USED FOR PILOT SCALE CUTTINGS CLEANING STUDY.

FIGURE 5

OIL RETENTION ON CUTTINGS - OFFSHORE DATA



BRINE IMPACTS TO A TEXAS SALT MARSH AND SUBSEQUENT RECOVERY

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Introduction

Salt water production is commonly associated with oil field activities. Creation of hydrocarbon storage facilities in salt domes produces large quantities of concentrated salt water (brine). Common disposal methods include deep well injection to salt water sands and dispersion via pipeline into surface waters. These activities are regulated by both state and federal provisions of the Clean Water Act.

Regulatory reporting requirements for spills of salt water are not as rigorous as for spills of oil and hazardous substances. These salt water spill reporting requirements are described in terms of a general prohibition against polluting waters of the state, and are entirely absent from the quantitative spill reporting requirements of the Clean Water Act and the Comprehensive Environmental Response Compensation and Liability Act. In this context salt water spills may be perceived as producing less ecological impact than oil or hazardous substance spills.

On June 22, 1989, approximately 8.3 acres of coastal marsh and the Gulf Intracoastal Waterway (ICW) were impacted by a major failure of a brine disposal pipeline. An estimated 35 million gallons of waste water ranging in salinity (as sodium chloride) from zero to 274 parts per thousand (ppt) was estimated to have discharged over an eight week period at two locations. Nearly 17 million gallons of this water (brine) had a salinity of over 220 ppt and was discharged during the first 7 weeks. Another 17 million gallons of brackish water (less than 25 ppt salinity) was used to perform the flow test which identified the failure. About 24 million gallons of salt water from a cluster of pipeline leaks severely impacted about 8.3 acres of coastal marsh. The remaining 11 million gallons of salt water was released from another cluster of leaks to the bottom of the Gulf Intracoastal Waterway where it was dispersed through the mixing effects of currents and commercial marine traffic.

On discovery of the spill an environmental assessment was initiated to quantify the extent of damage. This assessment facilitated a marsh recovery study which was conducted over the following ten months. The study evaluated vegetative damage and recovery, temporal changes to surface water physicochemis-

try, groundwater impacts, and soil salinity impacts and recovery. Review and analysis of the resultant data produced an excellent opportunity to evaluate the impact of highly saline water to a brackish marsh, and the resiliency of that marsh.

Methodology

The marsh recovery study incorporated three approaches. Vegetation was evaluated for damage and subsequently monitored for recovery throughout the study period. Surface water and soil salinities were monitored to assess and relate physicochemical conditions to vegetation recovery. Groundwater seepage from unconsolidated fill in the pipeline right-of-way was monitored for evidence of salt contamination. Figure 1 is a map of the study area showing the station locations used in this monitoring program.

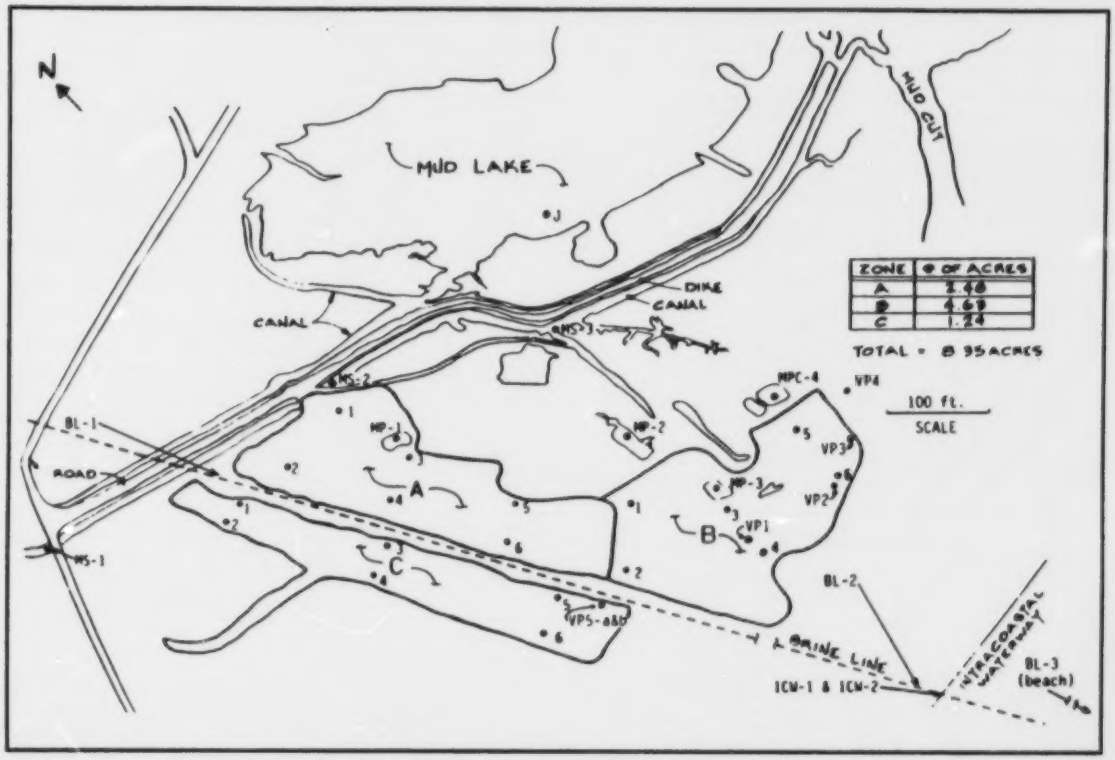

Figure 1. Salt Marsh Brine Impact Study Area.

The vegetation assessment consisted of quarterly ground level evaluations of four vegetation plots (VP1 to VP3 and VP5) established in heavily to lightly impacted areas. A fifth plot (VP4) was established outside of the impacted area as a control. Each plot consisted of a 10 meter radius around an identification stake. Species dominance, as percent foliage cover, and percent mortality were identified for each plot area in the field by three biologists

using the Daubenmire method (1). Changes in species diversity and mortality between assessments were determined. These assessments were augmented by aerial photographs (visible and infrared) of the area immediately after detecting the spill, to help establish the study area and sample locations, and one year later. Aerial and ground level photography were used to document changes in marsh appearance over time.

Surface and soil salinities were monitored periodically at twenty-six locations throughout the study area. Each monitoring station was identified in the field by numbered stakes recorded on a master map (Figure 1). Two additional stations in the ICW were monitored for soil and water salinity on a single occasion to assess the impact of released brine from that portion of the brine line.

Surface water salinities were determined by *in situ* electronic analysis. Salinities were analyzed at the base of the water column since the relative density of salt causes more saline waters to accumulate there. Temperature, dissolved oxygen, pH, and electrical conductivity were also monitored to supplement the study data.

Routine monitoring stations were established in four marsh ponds (MP-1 to 4), three locations in tidal ditches (MS-1 to 3), and in Mud Lake (J). Control stations were identified as MP-4 in the marsh ponds, MS-1 in the ditches, and J in Mud Lake which ties this monitoring data to over ten years of historical water quality data there. Two stations were also sampled on one occasion in the ICW. Monitoring frequency was biweekly for the first quarter followed by monthly thereafter.

Soil salinities were determined by laboratory extraction of salt using a deionized water wash followed by a chloride titration of the extract by method 4500-Cl^-B (2). Soil salinities were reported as parts per thousand (ppt) on a weight per weight basis. Soil samples were taken with a polypropylene coring device. Cores were taken in close proximity to each field station identification stake from relatively undisturbed substrate. One approximately three-inch long surface core was extracted and collected at each station for laboratory analysis.

Routine monitoring and control stations were the same as those described for the surface water salinity monitoring, plus six additional stations in each of three marsh zones (A-1 to 6, B-1 to 6, and C-1 to 6) in the 8.3 acre impacted area. Two stations (ICW-1 and 2) were also sampled on one occasion in the ICW. Monitoring frequency was biweekly (twice per month) for the first quarter, to detect rapid initial changes, followed by monthly there-after.

Groundwater was monitored periodically in three excavations (BL-1 to 3) along the brine disposal pipeline. Water in the bottom of the excavations was analyzed *in situ* during periods of high water when the excavations were flooded. During low water, when the excavations could be de-watered, samples of water draining directly from unconsolidated right-of-way fill were collected and analyzed. Location BL-1 is at the pipeline break in the impacted marsh area, BL-2 is just north of the ICW, and BL-3 is at the beach, where the pipeline

was excavated for inspection purposes immediately prior to its entry into the Gulf of Mexico. These locations are distributed over a distance of nearly two miles. Monitoring frequency was approximately biweekly for the first quarter and monthly thereafter, tidal and construction activities permitting.

Results

Vegetation assessments were conducted on June 26, 27, and 28; July 5; September 20, 1989; February 1; and April 24 and 25, 1990. The July and April surveys were supplemented and validated by a third party marsh vegetation expert (3 and 4).

Table 1 describes the common plant species observed in the impacted area, and their relative abundance. This species distribution is typical for a saline marsh as recognized by the U.S. Army Corps of Engineers (5).

TABLE 1
Relative Abundance of Common Plants in the Study Area

Common Name	Scientific Name	Abundance[A]
Saltgrass	*Distichlis spicata*	VA
Oystergrass	*Spartina alterniflora*	VA
Carolina wolfberry	*Lycium carolinianum*	VA
Sea-oxeye	*Borrichia frutescens*	A
Leafy threesquare	*Scirpus robustus*	A
Wiregrass	*Spartina patens*	A
Glasswort	*Salicornia* sp.	A
Gulf cordgrass	*Spartina spartinae*	LA
Seacoast sumpweed	*Iva annua*	LA
Narrowleaf sumpweed	*Iva augustifolia*	LA
Saltmarsh pluchea	*Pluchea purpurascens*	R
Seaside heliotrope	*Heliotropium curassavicum*	R

A: VA = very abundant, A = abundant, LA = less abundant, R = rare

Brine injured vegetation appeared confined to an 8.3 acre plot surrounding the brine line break. This area was subdivided into three zones, based on the severity of vegetation damage, as described by Figure 1 and below.

A. Zone A is 2.5 acres extending 120 yards along the east side of the brine line break area and bounded to the north by an access road. The elevation of zone A is low near the access road rising in a westerly and southerly direction. Zone A is poorly drained, allowing water to accumulate near the road. Nearly all vegetation in zone A was dead and severely decomposed in June 1989.

B. Zone B is 4.6 acres located south of zone A and east of the brine line. The zone is slightly higher in elevation than zone A, so predominant drainage from zone B is northerly (towards zone A). Some water does

drain to the east from zone B following high water conditions. Some brine flowed easterly from zone B as evidenced by an alluvial pattern of dead vegetation in the eastern part of the zone. Several shallow ditches that drain towards Mud Lake serve zone B. Vegetation injury in zone B ranged from completely dead to healthy in June 1989. Injury was most severe in the western portion of zone B.

C. Zone C is 1.2 acres paralleling zone A on the western side of the brine line. Drainage from zone A to zone C is blocked by a low linear mound of fill remaining on the right-of-way from the original line installation. Drainage from zone A into zone C occurs through low portions of the mounded right-of-way during high water conditions in the area. Most drainage in zone C occurs in a westerly direction via a slough that transects the zone. Injury in zone C also ranged from completely dead to unaffected vegetation in June 1989. The more severely injured vegetation was confined to the slough and low areas where brine apparently flowed from zone A.

Five circular plots in zones B and C were established in areas having no, and light to heavy plant mortality. The percent foliage cover for living and dead plants and the percent plant mortality by species in June, September, February, and April are described in Table 2.

Typical signs of salt injury observed during the June assessment were found on many plants in the vicinity of the break. These signs included complete plant death, and chlorosis or apical necrosis of plant leaves and stems. Severe deterioration of woody stem and root tissue was evident on many plants, particularly those within zone A. Necrotic or abscised leaves were not found on or around severely deteriorated plants, indicating that complete leaf decomposition had occurred. New growth was found on some recovering plants within the alluvial area of zone B and along the edges of the slough within zone C. The amount of decomposition found, coupled with the appearance of new growth, indicates that large quantities of brine were spilled within the area one to three months prior to identification of the leak, and that sufficient flushing (see discussion) had occurred to facilitate new growth.

During the September assessment substantial new growth was observed for several predominant species within certain plots. Salt tolerant *Lycium carolinianum* exhibited new growth in several of the impacted areas. Most striking was the appearance of a pioneer species, *Spartina alterniflora*, in VP5-a and b. This salt tolerant plant, initially not present in plot VP5-a and b, appeared to have taken advantage of the available niche left by damaged *Scirpus robustus* (90% mortality). Zone A, which has no vegetation plots, continued to exhibit little discernible vegetative recovery.

An unseasonably severe freeze occurred from December 21 through 25, damaging most of the remaining vegetation. The vegetation survey scheduled for December 1989 was delayed until early 1990 to provide an opportunity for some recovery from the freeze damage. The high mortality figures observed in February are in large part attributed to this atypical meteorological event. *Distichlis spicata* (65% mortality) and *S. alterniflora* (25% mortality)

TABLE 2

Percent Foliage Cover and Mortality (Death) for Predominant Species by Plot

Plot[A]	Species	June 1989		Sept 1989		Feb 1990		Apr 1989	
		Cov[B]	Death	Cov[B]	Death	Cov[B]	Death	Cov[B]	Death
VP1	*Lycium carolinianum*	70	97	70	80	70	95	65	85
	Distichlis spicata	30	100	5	50	5	60	15	10
VP2	*Lycium carolinianum*	80	70	75	45	65	80	45	80
	Distichlis spicata	20	85	65	30	60	80	65	15
VP3	*Lycium carolinianum*	25	30	25	10	25	95	15	95
	Distichlis spicata	80	25	85	15	85	60	90	15
VP4	*Lycium carolinianum*	30	15	40	3	15	95	10	90
	Distichlis spicata	60	5	75	4	80	70	90	10
	Scirpus robustus	5	2	5	2	5	57	5	5
VP5-a	*Lycium carolinianum*	30	10	10	1	0	-	0	-
	Distichlis spicata	60	15	70	5	70	60	75	5
	Scirpus robustus	10	15	2	98	15	100	45	5
	Spartina alterniflora	0	0	20	2	30	10	50	5
VP5-b	*Lycium carolinianum*	10	95	5	0	5	100	0	-
	Distichlis spicata	50	90	60	15	60	60	85	5
	Scirpus robustus	75	95	25	80	15	100	45	5
	Spartina alterniflora	0	0	5	40	10	40	25	5

A: VP5-a and VP5-b each represent one half of a 10 meter radius plot.

B: Percent cover based on estimate for both dead and living plants.

appeared to be less adversely affected by the cold weather than *L. carolinianum* (93% mortality) and *S. robustus* (87% mortality). Considerable new growth and few effects of the severe winter freeze were observed during the April survey.

Three marsh ponds (MP-1, 2, and 3) were the only surface water bodies to show elevated salinities as a result of the brine release (Table 3). These ponds are low areas in the marsh which act as sinks, retaining the dense brines that flowed into them during the release. Ponds MP-2 and MP-3 returned to ambient salinity conditions by August 8, with MP-1, the most severely impacted pond (located in zone A), returning to and remaining at ambient conditions on August 23. Depressed dissolved oxygen, observed in this pond through October (Table 4), was attributed to decaying biomass and high temperatures. All other surface water stations were consistent with their control stations and ambient conditions throughout this report period.

Abundant fauna was observed in and around all surface water bodies by August 1989. Observed fauna included stripped hermit crab, *Clibanarius vittatus*;

TABLE 3

Water, Mud, and Interstitial Soil Salinities (as ppt)

Area	Station	Jun[A]	Jul[A]	Aug[A]	Sept[A]	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Marsh	MP-1	152	33	24	30	21	24	26	14	18	8	8
Pond	MP-2	2	20	18	30	22	24	28	12	15	8	7
Water	MP-3	2	24	20	28	22	23	27	20	16	8	5
	MP-4[B]	2	12	18	29	21	24	25	23	19	8	7
Ditch	MS-1[B]	2	14	16	30	21	22	25	13	10	7	3
and	MS-2	1	16	18	30	22	22	26	12	13	7	3
Open	MS-3	2	16	18	30	21	22	26	15	14	8	4
Water	J[B]	2	16	16	16					11		8
	ICW-1		11									
	ICW-2		12									
	BL-1		20	35	102		29					23
	BL-2		21	10	24							
	BL-3			8	14							
Marsh	MP-1	110	50	46	20	15	10		13	7	6	9
Pond	MP-2	24	25	29	21	22	17		19	11	7	9
Mud	MP-3	69	76	34	32	23	16		18	9	7	9
	MP-4[B]	7	6	17	10	16	12		14	8	8	10
Ditch	MS-1[B]	3	5	14	5	9	13		9	3	6	11
and	MS-2	6	5	18	6	15	11		11	9	7	9
Open	MS-3	39	6	16	7	22	16		19	4	6	9
Water	J[B]	6	6	17	6					14		
Muds	ICW-1		5									
	ICW-2		6									
Inter-	A-1	94	50	44	14	22	6		12	13	7	11
stitial	A-2	23	36	36	12	14	14		10	15	12	6
Soil	A-3	40	29	23	26	15	13		8	11	6	6
Water	A-4	48	46	42	18	21	19		20	11	6	7
	A-5	24	26	22	14	18	16		14	10	7	7
	A-6	20	25	24	12	14	15		12	11	6	6
	B-1	10	20	28	15	19	18		47	30	16	4
	B-2	34	25	24	14	26	16		19	11	7	8
	B-3	20	22	28	16	10	17		20	11	5	5
	B-4	12	26	30	29	15	19		25	26	11	11
	B-5	10	12	20	16	12	19		14	13	6	4
	B-6	10	14	21	16	18	16		21	16	6	3
	C-1	6	7	22	9	11	18		13	16	20	11
	C-2	6	6	19	9	15	20		11	11	9	7
	C-3	8	14	22	14	26	20		26	13	21	14
	C-4	6	5	17	14	13	14		14	10	10	8
	C-5	8	8	22	18	27	16		17	16	8	10
	C-6	6	5	17	13	14	14		10	7	6	6

A: Data represents an average of up to four data points these months.

B: Control stations.

TABLE 4
Additional Surface Water Physicochemical Parameters

		1989							1990			
Parameter	Station	Jun[A]	Jul[A]	Aug[A]	Sept[A]	Oct	Nov[A]	Dec	Jan	Feb	Mar	Apr
Temper-	MP-1	29	28	27	29	24	21	5	12		16	28
ature	MP-2	28	28	27	30	24	20	5	13		17	28
(^{o}C)	MP-3	28	28	28	30	24	20	6	14		17	30
	MP-4[B]	28	28	28	30	25	21	6	14		18	27
	MS-1[B]	30	31	28	29	25	21	4	13		16	29
	MS-2	27	31	27	29	25	21	3	16		16	28
	MS-3	28	27	30	31	24	21	9	14		16	30
pH	MP-1	7.0	8.4	7.8	7.8	6.9	7.3	7.7	8.0	8.1	7.7	7.6
(SU)	MP-2	7.6	8.4	7.9	7.7	7.2	7.2	7.6	8.1	4.0	8.0	7.7
	MP-3	7.6	8.6	8.0	7.8	7.3	7.2	7.8	7.9	3.5	7.8	7.8
	MP-4[B]	7.8	8.0	8.0	7.8	7.3	7.7	7.7	8.0	4.4	8.0	7.7
	MS-1[B]	7.1	8.5	7.8	7.3	6.7	7.0	7.3	7.0	6.3	7.4	7.7
	MS-2	7.4	8.1	7.5	7.4	6.8	7.0	7.6	7.3	7.4	7.4	7.6
	MS-3	7.6	7.8	7.4	7.6	7.2	7.0	7.6	7.7	6.0	7.5	7.8
Dissolved	MP-1	2.0	5.8	2.6	3.2	1.1	1.0	8.3	10.2		6.2	5.1
Oxygen	MP-2	5.9	3.5	7.0	8.6	5.0	2.4	8.1	10.5		7.4	5.9
(mg/l)	MP-3	6.4	6.9	7.6	10.0	6.2	2.2	8.5	7.7		6.5	7.4
	MP-4[B]	6.4	4.0	6.8	7.2	4.5	4.8	7.5	8.1		7.9	6.1
	MS-1[B]	3.5	6.4	7.0	2.4	0.7	1.9	9.2	5.1		6.1	6.8
	MS-2	4.4	4.9	4.4	4.5	0.9	2.2	8.7	6.3		7.4	6.3
	MS-3	5.9	4.6	6.5	6.1	5.2	2.3	11.0	10.6		6.0	7.4
Conduc-	MP-1	182	50	41	28	35	38	42				
tivity	MP-2	5	31	30	29	35	37	43				
(umho)	MP-3	5	39	33		35	37	42				
	MP-4[B]	5	20	30		37	38	40				
	MS-1[B]	3	29	27		35	35	39				
	MS-2	4	26	30		35	35	40				
	MS-3	5	27	30		3	34	40				

A: Data represents an average of up to four data points these months.

B: Control stations.

fiddler crabs, *Uca* sp.; blue crab, *Callinectes sapidus*; periwinkle snails, *Littorina* sp.; sailfin molly, *Poecilia latipinna*; sheepshead minnow, *Cyprinodon variegatus*; broad-banded water snake, *Nerodia fasciata*, common egret, *Casmerodius albus*; green heron, *Butorides virescens*; roseate spoonbill, *Ajaia ajaja*; osprey, *Pandion haliaetus*; and coyote, *Canis latrans*. There was no attempt to quantify these organisms. Cooler temperatures at the end of 1989 and in early 1990 may have tempered the observed activity of this fauna.

Elevated soil and mud salinities were more persistent in the impacted areas (Table 3). Marsh ponds MP-1 through 3 and Zone A were most persistent with elevated soil salinities. These marsh ponds, as a group, reached soil salinities tolerable for the more hearty vegetation (about 50 ppt) by August 1989. The soil salinity in marsh pond MP-3 remained about twice that of the control station on September 20, while marsh ponds MP-1 and 2 were consistent with the control station. By November 21 variation of the marsh ponds relative to the control station had declined to and remained at only 5 ppt. No evidence that rooted bottom vegetation existed in the marsh ponds prior to the brine release was observed.

One zone A and one zone B soil salinity also remained elevated as of September 20. By October 17 all marsh soil salinities had recovered to essentially ambient conditions, although some individual stations exhibited minor periodic swings in salinity attributed to sample heterogeneity.

Neither soil nor water samples indicated any observable salinity impact in the ICW (Table 3). This is attributed to the shallow morphology of the canal, severe mixing turbulence imposed by barge traffic, and the close communication of this area with the Gulf of Mexico. Monitoring of this station was therefore discontinued in July.

No producing aquifers were identified during excavation of the brine pipeline to expose pipe failures for repair. This observation was substantiated by an independent hydrogeologist (6). Some small amounts of groundwater were observed draining into the excavations. This groundwater seepage into the three brine line excavations was monitored as construction activities and weather allowed (Table 3). Excavations at the ICW (BL-2) and the beach (BL-3) showed no indication of measurable salt contamination. All samples at these locations were similar in salinity to nearby surface waters. The salinity at the initial leak location (BL-1) was observed at significant levels (85 to 110 ppt) from September 1 through 18. By November, groundwater salinities at BL-1 declined to within ambient marsh conditions. This groundwater was observed seeping from unconsolidated fill in the original pipeline excavation, rather than a producing sand or aquifer.

Discussion

The study area was frequently inundated with heavy rains and or tides during the early portion of this study. Tropical storm Allison (landfall on June 26, 1989) and hurricanes Chantal (landfall July 31, 1989) and Jerry (landfall October 15, 1989) made significant contributions to flushing brine and salt laden waters from the impact area, and its soils. Severe cold weather in December 1989 (see Table 4) resulted in extensive necrosis of the exposed vegetation. Significant recovery from this freeze damage was evident by April 1990.

The more salt tolerant plants such as *L. carolinianum* and *D. spicata* recovered significantly in all but the most severely impacted areas. *D. spicata* also exhibited tolerance to the cold weather. *S. robustus*, a somewhat less salt tolerant species, has been significantly affected in some areas, declining in

distribution and density. *S. alterniflora* has moved into some of the impacted areas as a pioneer species filling the niche vacated by *S. robustus* in zone C. *S. alterniflora* also exhibited some tolerance to the cold weather. As of April 1990 vegetation in all but about two and a half acres of impacted area showed at least partial recovery.

Water and soil salinities were consistent with the early recovery observed in most of the marsh vegetation. The salinity of surface water stations quickly declined to ambient conditions. Recovery of soils was slower than water quality, as might be expected, due to the more limited mobility of interstitial waters and salts. Frequent natural flushing throughout the study period appeared to augment flushing of salt and nutrient exchange.

The elevated groundwater salinities in BL-1 were believed to represent a return of brine lost to unconsolidated fill around the brine pipeline. These salinities eventually returned to typical marsh salinities suggesting measurable release of brine from unconsolidated fill is complete. This contamination was of minimal ecological impact. No aquifer or sand was cut by the brine line excavation suggesting extensive groundwater contamination did not occur. Monitoring of this fluid will continue as precipitation and tidal conditions permit.

Conclusion

Measurable surface water and soil impacts were relatively short lived due to a variety of factors. Frequent and severe tidal and precipitation events provided excellent natural flushing to the marsh. The shallow morphology, heavy commercial barge traffic, and close communication with the Gulf of Mexico facilitated rapid dispersion in the ICW. This rapid physicochemical recovery facilitated a corresponding response in the local flora.

Vegetation in study zones B and C exhibited pronounced recovery during the first quarter, and continued recovering throughout the study period. Most of the vegetative damage in these zones was confined to leaves and stems allowing recovery to be initiated by the relatively unimpacted roots and rhizomes. This limited damage is attributed to the slightly higher elevation of these zones preventing prolonged penetration of the brine into the substrate, and the frequent flushing by tides and precipitation. Recovery was interrupted by freeze damage, but continued once this meteorological anomaly passed.

Study zone A showed little vegetative recovery during the study. Coupled with high initial soil salinities, this suggests more extensive damage to the vegetation in zone A. The low relief of this area and its proximity to the brine source lengthened and intensified the brine exposure, producing deep root damage and a more prolonged soil impact. Return of the soil salinity to ambient conditions suggests that at least some natural revegetation may occur by runners on the perimeter, and by seeds if adequate transport into the area is achieved. Periodic long term monitoring of the vegetation in this area will continue in order to track recovery. Enhancement of circulation and

scattered planting of *S. alterniflora* are under consideration as feasible actions to provide a seed source to the area.

Spring growth produced significant recovery and some species redistribution in all but the most severely impacted area. The shift in species dominance is an expected phenomenon in an area, such as this, where the primary physicochemical conditions were significantly altered. Return of the physicochemical parameters to suitable conditions facilitated initial revegetation by the heartier species. This phenomena allowed these species to establish themselves in several new areas, and provided an opportunity for them to expand their distribution in these areas.

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BRINE MANAGEMENT PRACTICES IN OHIO

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The Division of Oil and Gas was created as the primary agency with authority to regulate Ohio's oil and gas industry by conservation legislation enacted in 1965. Serving a dual mission, the Division protects the public health, safety and environment during the course of oil and gas operations while allowing the development of Ohio's non-renewable energy resources. Today, the Division is responsible for an industry which has grown to over 64,000 wells and 3,500 registered well owners.

Ohio's UIC Class II well program was granted primacy by U.S. EPA, effective in September, 1983. The program has acquired a broad range of regulatory responsibilities which assists the State in tracking of oilfield brine and associated wastes. To protect underground sources of drinking water, the Class II program enforces regulations concerning: transportation of brine; tracking of wastes; inspection of injection well surface facilities and pipelines; and approving resolutions for dust and ice control. However, the primary focus of the Class II program is centered on the four methods of brine disposal allowed by State law. These methods include; conventional injection wells, enhanced recovery projects, road-spreading for dust and ice control, and annular disposal.

Wells constructed for deep injection, or conventional injection wells are typically designed with multiple layers of sealed casing to protect freshwater aquifers. The surface casing is set at least 50 feet below the lowest U.S.D.W. and cemented to the surface. The production casing must be cemented a minimum of 300 feet above the top of the injection zone and tubing is set on a packer creating a monitored annulus. At current staff levels, UIC inspectors witness 100 percent of all critical well construction phases including installation and cementing of casing and installation of tubing and packer.

Before granting a permit for injection, an "area of review" must be evaluated, a legal notice is published in a newspaper of general circulation in the area where the proposed well is located, and a public hearing may be held depending upon the validity of objections raised.

After an initial mechanical integrity test is performed on the injection well, continuous monitoring of the annulus is an acceptable means of determining ongoing mechanical integrity as long as sufficient pressure is maintained to detect leaks. If positive pressure cannot be maintained on the annulus for a prolonged period of time, a monthly mini-test is required and mechanical integrity must be demonstrated once every five years. At current staff levels,

UIC inspectors witness 100 percent of all mechanical integrity tests and inspect annular pressure readings once every six weeks, on average. If annular and injection tubing pressures equalize, injection operations are immediately suspended by order of the chief until corrective action is taken and the UIC inspector witnesses a successful mechanical integrity test.

Most of the 186 conventional injection wells in Ohio are converted production wells geographically distributed in 36 counties and known producing fields. Since the majority of the wells are commercial, the associated production costs are greatly increased with brine disposal rates averaging between $1.50 and $2.50/BBL depending upon transportation distances. Over 92% of reported brine production of 8.9 MM/BBLs was injected in conventional wells during 1988. A relatively small percentage was disposed of by annular disposal or road-spreading for dust and ice control.

Concerns that are frequently raised over deep injection wells vary greatly in Ohio. One area of interest is the ongoing research by Columbia University, the United States Geological Survey and others on the possibility that these wells are triggering earthquakes in the northeast portion of the State. Additionally, the Division has developed mini-task force groups composed of qualified personnel, industry representatives, and constituents to establish recommendations on "Parameters for Maximum Injection Pressures" and "Guidelines for the Construction of Surface Facilities" in an effort to resolve complicated technical and economic issues. The Division also encounters regular objections at public hearings concerning problems with aesthetics of the proposed facility, transportation restrictions, zoning regulations, and the possibility of freshwater or other environmental damage.

Wells constructed for injection in Ohio's enhanced recovery projects must meet the same construction, testing and monitoring requirements as deep injection wells. Enhanced recovery projects operate in 16 counties statewide with 171 injection wells and 302 withdrawal wells. The total volume of fluid injected during 1988 was approximately 1.2 MM/BBLS.

Because of its favorable reservoir characteristics (high permeability, lenticular channel deposits, shallow depth and estimated oil reserves) the Berea Sandstone is effectively the only reservoir in Ohio successfully supporting secondary recovery. However, the Berea has been historically drilled and accurate well records are often non-existent or less than adequate to demonstrate that well construction and plugging methods meet today's standards. Therefore, several producing fields are currently static since the area of review typically contains 100 to 200 wells and economic conditions cannot support the up-front costs of rejuvenating these potential enhanced recovery projects. However, the UIC Program has been creative in evaluating proposals for such projects by: issuing permits contingent upon completing corrective action requirements in the area of review, or allowing the use of monitor wells to ensure that reservoir static fluid levels do not rise as a result of injection potentially resulting in contamination of U.S.D.W.'S.

The UIC Class II Program maintains strict standards over road-spreading resolutions, which are passed by local government authorities. Presently, 10 counties, 171 townships, and 15 municipalities statewide have passed valid resolutions to allow brine spreading for dust and ice control. Approximately 362,000 BBLs or 3.8% of brine produced was reportedly spread on Ohio's roads in 1988.

Surface application of brine remains an environmentally controversial method of disposal. While injection of brine into conventional Class II wells is recognized as the preferred method of disposal in Ohio, the General Assembly determined that insufficient evidence of environmental harm existed to prohibit alternate, less expensive disposal options. However, in response to environmental concerns, the legislature created a Brine Management Research Special Account to fund research concerning alternate brine disposal methods.

To date, four research projects have been funded at a total cost of approximately $107,000. This research has answered many of the questions concerning the environmental acceptability of the surface application method. Funded research projects include:

- A preliminary study of aromatic hydrocarbon concentrations in Ohio oilfield brines;
- A study of trace metal concentrations in Ohio brines;
- A field study to monitor soils and groundwater quality changes caused by surface application of brine under worst case aquifer conditions; and
- A study of volitalization of aromatic hydrocarbons in brine from wellhead to road surface.

Findings from the study on brine application under worst case aquifer conditions showed that localized saline contamination of ground water occurred temporarily following both winter and summer spreading episodes. However, there was no evidence of aromatic hydrocarbons or increases in heavy metals concentration in the aquifer. Copies of this study, conducted by the Ohio State University, are available at cost through the Division's Public Inquiries Assistant.

Annular disposal of brine is under Class II jurisdiction even though construction standards and the disposal method differs considerably from conventional injection wells. New rules, enacted in July 1989, have strengthened well construction requirements and mandate demonstration of mechanical integrity prior to disposal authorization. However, the following major differences between annular disposal and conventional injection remain:

- There is only one layer of casing that protects freshwater aquifers in an annular disposal well. Surface casing must be set at least 50 feet below the lowest U.S.D.W.

- Average daily volumes injected are limited to a maximum daily average of 10 BBLS.

- The injection zone is not defined in an annular disposal well.

- An Inspector must witness setting the surface casing. Upon inspection of the liquid tight piped system, the well owner is granted authority to dispose of on-lease brine by the annular disposal method.

- There is no area of review established for annular disposal wells.

- On all annular disposal wells, brine is gravity-fed into the injection zone.

- Most annular disposal wells are located in a five-county area of east-central Ohio and are drilled by cable-tool rigs. It is suspected that the Berea Sandstone and the Newburg Dolomite are the major inherent injection zones since annular disposal is only practical when drilling problems created by brine production are encountered in those zones.

- Most annular disposal wells meet the stripper classification and are marginally economical utilizing this practice. Any further production costs may considerably shorten the economic life of the well.

- Only 3.6% of 350,000 BBLS of brine produced was reportedly injected using the annular disposal method in 1988.

Annular disposal has long been suspected as a cause of damage to U.S.D.W's; however, there is relatively little documentation that this has actually occurred. Much of the controversy surrounding annular disposal centers on unanswered questions regarding the practice.

The UIC Section has been successful in answering many questions concerning annular disposal by performing in-depth research on the practice. This research, funded by both the U.S. EPA and Division of Oil and Gas, evaluated actual casing and sealant conditions in the field on one-hundred wells permitted to use annular disposal. In summary, this study demonstrated that the practice of sealing surface casings with prepared clay was not effective in isolating or protecting underground sources of drinking water. Ninety-seven of one-hundred wells evaluated were determined to be inadequately sealed. As a direct result of this research, strengthened regulations were adopted which require annular disposal wells to have surface casing sealed with cement under an inspector's supervision and an initial mechanical integrity test of the well prior to commencement of disposal operations.

In 1988, the UIC Section initiated the mechanical integrity testing requirement addressing all annular disposal wells permitted prior to September of 1983. This effort was mandated by the once every five year testing requirement contained in Ohio's regulations.

To date, 6,334 wells have had authorization to use annular disposal revoked by Chief's order for failure to perform the required mechanical integrity test. With assistance from the Division of Oil and Gas field staff, in excess of 5,400 of these wells have been field-checked for compliance with the orders. Only 135 wells have been tested by operators to date. Out of this number, 104 wells successfully demonstrated mechanical integrity and have had authorization to use annular disposal extended for five years. Currently, there are only 1,560 wells authorized to use annular disposal in Ohio. This number is anticipated to continue the dramatic decline that began in 1988 as mechanical integrity testing requirements continue to be enforced.

Some other areas of interest regarding brine disposal in Ohio relate to the U.S. EPA mid-course evaluation of Class II Programs, and the Underground Injection Practices Council (UIPC) Peer Review process.

Ohio was one of five states selected to participate in the national mid-course evaluation effort for Class II wells. This evaluation looked primarily at the adequacy of existing regulations for Class II wells nationwide. Findings indicated that overall, current regulations are for the most part adequate.

The UIPC Peer Review of Ohio's Program was conducted in February, 1989. This process consisted of a review team composed of State UIC Directors from two primacy states, a previous State Director and the UIPC Technical Director. The week long review critically examined all aspects of Ohio's brine disposal program. The findings, which were published and are available through the UIPC, demonstrate that Ohio is very much in the forefront nationally with a progressive UIC Program. Additionally, the Peer Review Report closely parallels bi-annual U.S. EPA evaluations of the program. In fact, Region 5 of the U.S. EPA has consistently used Ohio's program as a model for other states to utilize.

Currently, a major area of concern centers on federal funding available for Ohio's UIC Program. Since receiving primacy in 1983, annual federal grants have only funded approximately 25 percent of the total program's cost. The State's dedication to the program and willingness to pick up the lion's share of program funding has enabled a model Class II UIC program to develop in Ohio. It is critical, however, that both U.S. EPA and Congress recognize that in order to maintain quality programs in Ohio and other states, it is necessary to provide adequate funding.

Over the last 24 years, the Division has grown with Ohio's oil and gas activity and has responded progressively to issues and concerns from industry, local and state officials, special interest groups and the general public. The Division's UIC Class II program shares this same progressive attitude by acknowledging broad responsibilities and high expectations for the future.

CHARACTERIZATION OF TREATMENT ZONE SOIL CONDITIONS AT A COMMERCIAL NONHAZARDOUS OILFIELD WASTE LAND TREATMENT UNIT

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K. W. Brown & Associates, Inc.

Introduction

Campbell Wells Corporation (CWC) operates two commercial land treatment facilities in the State of Louisiana; the Jennings Facility (Jeff Davis Parish) and the Bossier Parish Facility. Both are permitted through the Louisiana Department of Natural Resources for the treatment and disposal of nonhazardous oilfield waste (NOW), as defined in Statewide Order 29-B.

Land treatment has proven to be a successful treatment method for organic wastes, as well as conservative pollutant species (heavy metals). However, a primary concern for land treatment of oilfield wastes is the high soluble salt concentrations and the potential for these soluble salts to move vertically out of the treatment zone. The objective for soluble salts management is to limit vertical mobility and impacts to groundwater. CWC removes soluble salts from its treatment cells primarily via the surface water runoff pathway.

Routine treatment cell monitoring at both CWC facilities includes quarterly soil core and soil-pore water samples. The soil-pore water samples, collected from lysimeters, are designed to provide chemical data for water moving through the treatment zone. The Jennings facility, which began operation in December 1983, has been unable to collect consistent water samples in their lysimeters, even though the lysimeters are functional. Since migration of soluble salts into the subsoil represents a potential offsite impact, and thus may influence the operating life of the facility, CWC decided to conduct a subsoil study in one of their older treatment cells to better define the potential movement of soluble salts.

Study Objectives

This field investigation was conducted to characterize the subsoil conditions of one of the older treatment cells at the CWC facility. The specific objectives of the field investigation were:

1. to determine the effect of land treatment operations on the physical and chemical properties of the subsoil;
2. to quantify flow rate of soil-pore liquid through the subsoil;
3. to develop site-specific data to determine if barium is being attenuated or is otherwise unavailable for migration; and
4. to further document the impacts or lack of impacts of land treatment of NOW at the CWC facility.

Investigative Approach

The investigation was divided into the following tasks: 1) field infiltrometer tests, and 2) soil sampling and description activities. A treatment cell (Cell 2) and a background location were chosen for this study. Cell 2 was one of the original treatment cells permitted in 1983. This cell is typical of the treatment cells at CWC, both in construction and management. Cell 2 had recently concluded a treatment cycle and the treated NOW had been excavated. Therefore, the surface of the subsoil was exposed and available as the "surface" for this study.

Field Infiltration Study

An infiltration study was undertaken to determine the rate at which water infiltrates the treatment zone soil. Four separate infiltrometer test sets were conducted for this study. The first set of three infiltrometer tests were conducted in Cell 2 at the subsoil surface. The second set of three were conducted adjacent to the first set, at a depth of 18 inches below the subsoil surface. Sets three and four of the infiltration runs were conducted at the background location, at corresponding depths within the soil profile.

Double-ring infiltrometers were used to determine the infiltration rate of the treatment zone materials. This equipment consisted of three pair of 12-inch high steel cylinders. The inner cylinder or ring of each pair was 12 inches in diameter, while the outer cylinder was 30 inches in diameter. The purpose of the inner ring or cylinder was to allow a measure of flow rate into the soil, while the outer ring wetted the surrounding soil to ensure that flow from the inner ring was vertical. The cylinders were open at both the top and bottom, and the bottom edge was beveled for ease of insertion into the soil. A 50-gallon barrel was used to supply water to each outer ring and a 3-foot high, 6-inch diameter cylinder was used as the supply for the inner ring.

Depth of water in both cylinders was maintained at approximately 2 inches above the soil surface with automatic float valves. A Stevens Hydromark water level chart recorder was used to continuously record the water level in the inner ring water supply cylinder. Sufficient time was allowed during the test for the wetting front to advance at least 6 inches into the soil. This ensured a 6-inch depth of saturated soil with an infiltration rate approaching a steady state value.

Soil samples were collected to measure the native field water content of the soil before the tests were started and immediately after the infiltration test to indicate the percent saturation of the soil below the test ring.

Subsoil Characterization Procedures

Procedures to define subsoil conditions were divided into two phases: soil chemical and soil physical properties, both of which were accomplished by means of soil pits excavated in the soil. Three soil pits were excavated in Cell 2 to a depth of 5 feet, measured from the undisturbed soil horizon directly beneath the waste treatment zone. In addition, one background pit was excavated for comparison. Each soil pit was described and sampled in accordance with the procedures outlined below. A track hoe was used to excavate the pits, with the operator creating a vertical pit wall used for soil descriptions and sample collection.

Soil Description -- Detailed descriptions of the profiles were made and compared with data collected from similar adjacent background areas. The soils were described and classified according to standard soil survey procedures.

Soil Sampling -- Soil samples were collected at continuous 3-inch intervals from the lower boundary of the waste treatment zone to a maximum depth of 5 feet. Selected samples were analyzed in order to define concentration gradients. Chemical properties analyzed included soluble cations, soluble anions, pH, electrical conductivity, and selected metals (e.g., total barium and zinc). Physical properties included soil moisture percentage, water retention capacity, bulk density and particle density.

Results

Treatment Cell 2 was chosen for this study. The field investigation was conducted during the last week of September and the first week of October 1988. Three soil pits were located randomly and excavated in Cell 2, with a background soil pit excavated at the nearest accessible native soil location (Fig. 1). Infiltration runs were conducted in Cell 2 and at the background site, as noted in Figure 1.

Historical Use Of Treatment Cell 2

The treatment cycle for each treatment cell consists of an application, a dewatering, and a treatment cycle. Once the treatment cycle is completed, and the treated NOW meets specified criteria established by the DNR, the treated NOW can be removed from the treatment cell. During treatment cell construction, the topsoil is removed, therefore, applications are made to the surface of the subsoil. The treatment zone consists of the Waste Treatment Zone (applied NOW), the Upper Treatment Zone (subsoil surface to 12 inches), and the lower treatment zone (12 to 54 inches).

At the time of the study, Cell 2 has undergone three application cycles since the initial facility start-up in 1983 (Table 1). NOW applications ranged between 16,000 and 26,000 barrels/acre, with the average treatment time being about 18 months. Gypsum (26 tons/acre) was applied during the third cycle.

Table 1. Application History of Cell 2.

Beginning Application Date	Barrels/Acre	End of Treatment	Total Treatment Months	Gypsum App. (tons/acre)
1st Q., 1984	*	8/85	~20.0	0
Sept. 30, 1985	26,000	11/1/85	23.6	0
Nov. 25, 1987	16,123	9/15/88	10.0	26

* CWC opened in Dec. 1983. No records were kept relating barrels applied per acre for early applications. It is assumed that Cell 2 received applications in early 1984. The first excavation for Cell 2 occurred in mid-1985.

Soil Description

The Soil Conservation Service (SCS) has mapped this area as Crowley/Vidrine Complex, with a small area of Mowata Series mapped for Cell 2 (Fig. 1). According to the SCS, the Crowley/Vidrine and the Mowata series are geographically competing series. Primary differences between these soil series are:

1. Mowata soils have tongues of A2 extending into a B horizon; and
2. the Crowley/Vidrine soils are on slightly higher convex shaped surfaces surrounding Mowata soils.

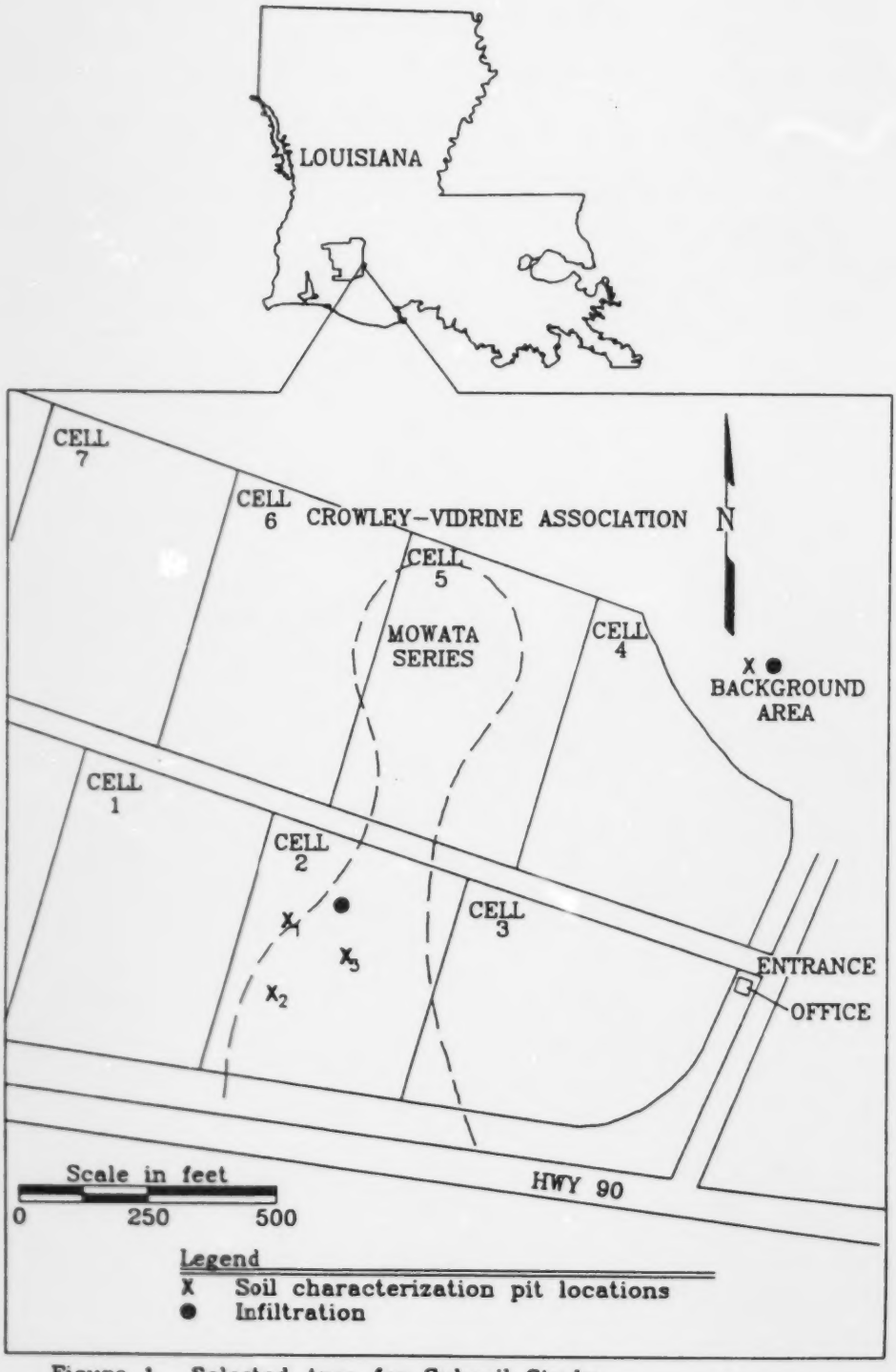


Figure 1. Selected Area for Subsoil Study.

Thus the surface horizons and the location within the landscape are the reason these soils are mapped separately. The subsoils for the series are very similar. Therefore, while there may be minor differences with the surface soils for the soil pit and background locations, it was determined that the subsoils were similar, and comparisons between these four pits is appropriate for this study.

The subsoil for both the Crowley and the Mowata soil series have silty clay and silty clay loam horizons. Calcium carbonate concretions were visible in all soil pits, with the exception of soil pit 3. Both the Crowley and the Mowata soil series have calcium carbonate concretions in their subsoil (36 to 60 inches).

As a result of cell construction and operations, the existing subsoil surface in Cell 2 is equivalent to an approximate 18-inch depth in the background area. Therefore, sampling and data interpretation accounted for this effect to compare data for equivalent soil depths. For comparison to Cell 2 data, except where noted, the background data is presented as 18-inch being 0-inch (subsoil surface).

Infiltration Tests

Infiltration tests were conducted at the surface of the cell (surface) and 18 inches below the surface (subsurface). For the background location, tests were conducted at 18- and 36-inch depths, corresponding to the same soil horizons.

The infiltration data indicate that water movement through these soils is very slow. The infiltration rates for the surface and subsurface were 1.7×10^{-6} cm/sec (0.002 in/hr) and 5.54×10^{-6} cm/sec (0.008 in/hr) (Table 2) (Fig. 2a and 2b). The infiltration rates for the background soils were 7.7×10^{-7} cm/sec (0.001 in/hr) and 1.43×10^{-6} cm/sec (0.003 in/hr) (Fig. 3a and 3b). Given the data scatter, however, the background subsoils' hydraulic conductivities were about the same as the subsoils within Cell 2. It should be noted that the measurement limit for the double-ring infiltrometer is usually around 1×10^{-6} cm/sec. Therefore, all of the measurements in this study were near the limit of detection for this instrumentation. It is possible that the final infiltration rates (saturated hydraulic conductivities) are lower than those reported.

Table 2. Hydraulic Conductivity and Permeability Classes.

Infiltration Test Location	Hydraulic Conductivity (in/hr)	Hydraulic Conductivity (cm/sec)	Permeability Class
Cell 2			
Surface	0.0023	1.72×10^{-6}	Very Slow
Subsurface	0.0025	5.54×10^{-6}	
Background			
18" Depth	0.0011	7.74×10^{-7}	Very Slow
36" Depth	0.0027	1.43×10^{-6}	

The average pre-infiltration soil moisture for Cell 2 surface and subsurface and the background 18- and 36-inch depths were similar, ranging from 21.5 to 26.3% (Table 3). The post-infiltration soil moistures were different, with the Cell 2 moisture only increasing by about 28%. The background 18- and 36-inch depths had a 50% change in soil moisture.

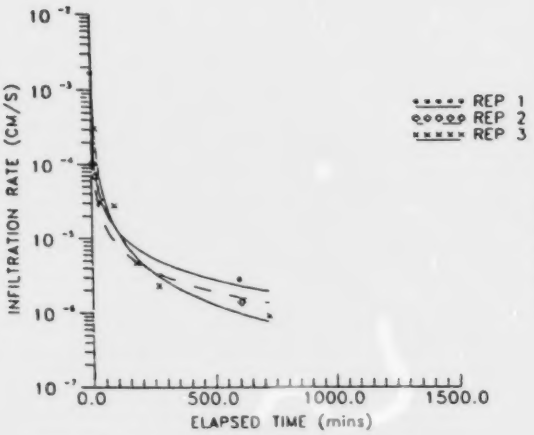


FIGURE 2a. INFILTRATION RATE AT SOIL SURFACE IN CELL 2.

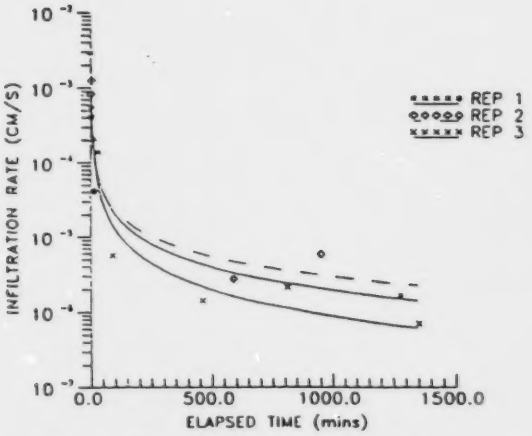


FIGURE 2b. INFILTRATION RATE AT SUBSURFACE IN CELL 2.

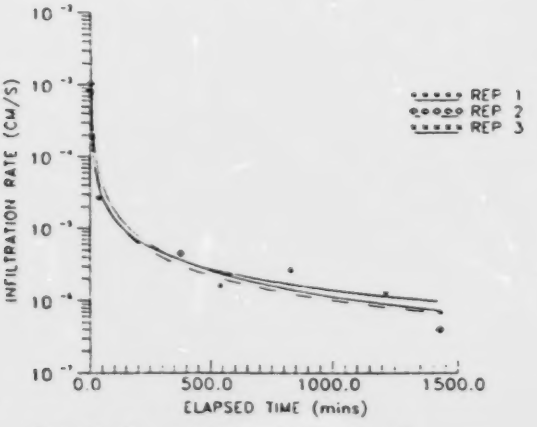


FIGURE 3a INFILTRATION RATE AT 18 INCHES DEPTH IN BACKGROUND AREA.

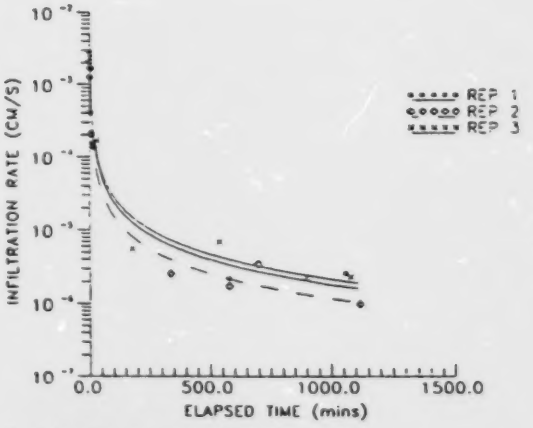


FIGURE 3b. INFILTRATION RATE AT 36 INCHES DEPTH IN BACKGROUND AREA.

Table 3. Soil Moisture Before and After Infiltration Tests.

Location		Before	After
Cell 2 - Surface	Rep 1	23.8	30.3
Cell 2 - Surface	Rep 2	22.1	29.2
Cell 2 - Surface	Rep 3	21.5	27.2
	Average	22.5	28.9
Cell 2 - Subsurface	Rep 1	22.0	28.8
Cell 2 - Subsurface	Rep 2	21.4	27.8
Cell 2 - Subsurface	Rep 3	21.1	25.9
	Average	21.5	27.5
Background - Surface	Rep 1	22.7	39.9
Background - Surface	Rep 2	24.9	43.4
Background - Surface	Rep 3	30.7	50.9
	Average	26.1	44.7
Background - Subsurface		24.9	43.6
Background - Subsurface		29.2	44.0
Background - Subsurface		24.6	38.3
	Average	26.3	42.0

Soil Analytical Data

The soil textures ranged between silty clay and silty clay loam. While the horizons varied somewhat with depth, the soils were fairly consistent for the depths studied. Based on this observation, this discussion will not attempt to discuss the chemical data in accordance with the natural variations within the soil profiles. It is felt that this would greatly complicate the discussion on the soil chemical data, and would only have limited utility. It is realized that some of the variations within the four soil pits on a depth basis may be affected by the different horizons.

Chemical Data -- Soluble salts, as measured by electrical conductivity (EC), were elevated for all three pits for the surface 18 inches, with the greatest increase in the surface 3 inches (Fig. 4). Below 18 inches, soil EC values were below 1 mmhos/cm, and generally at or near background soil EC. A slightly higher soil EC was noted at 48 and 60 inches in Pits 1 and 2. This higher EC is primarily due to naturally occurring soluble salts, primarily sodium bicarbonate. The soluble sodium concentrations are higher (4.74 meq/L) at 48 and 60 inches than the soils between 9 and 45 inches, therefore, it is concluded that the increased sodium is a natural occurrence. Bicarbonates are generally low in all four soil profiles above 3 feet.

The soil pH values also reflect the impact of the soluble salts in the first 18 inches. The background soil pH reflects a well leached surface soil, with a pH of 5.4 to 5.8 for the first 18 inches, which grades into an alkaline system near 3 feet (Fig. 5). Pit 1 (0 to 6 inches) and Pit 3 (3 to 9 inches) both have a zone of lower pHs, which reflect some of the natural pH values. Soils in Pit 2 have pH values above 6.7 throughout the pedon.

The primary soluble ions of concern with oilfield wastes are sodium and chloride. Chloride concentrations were elevated in the first 18 inches of the soil profile, but were generally near background concentrations below 18 inches (Fig. 6). At 6 feet, the average chloride concentration for the three pits was approximately 14 mg/kg above the background value. No significance is placed on this minor increase. Sulfates at 4 and 5 feet reflected no increase above background concentrations.

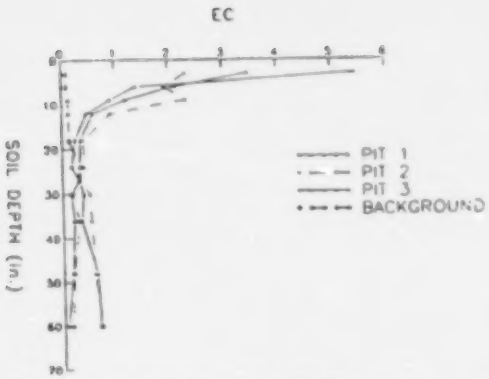


FIGURE 4 ELECTRICAL CONDUCTIVITY (mmhos/cm) FOR SOIL PROFILES

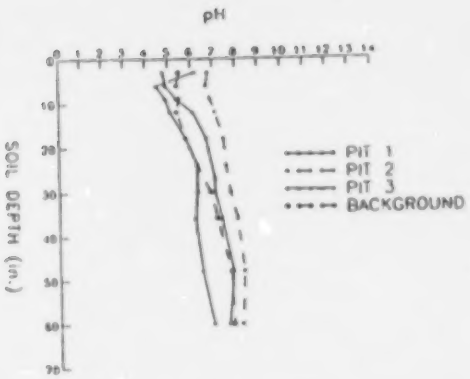


FIGURE 5 pH FOR SOIL PROFILES

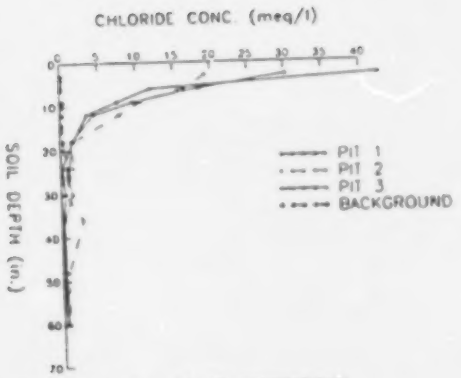


FIGURE 6 CHLORIDE CONCENTRATIONS (meq/l) FOR SOIL PROFILES

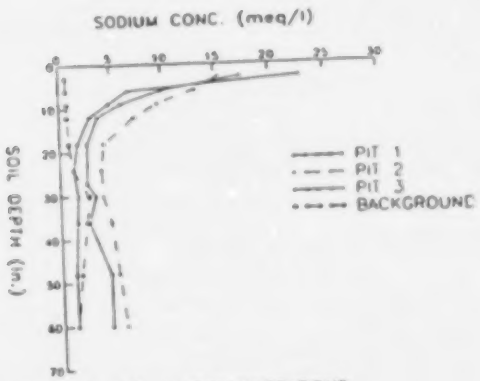


FIGURE 7 SODIUM CONCENTRATIONS (meq/l) FOR SOIL PROFILES

Soluble sodium concentrations varied between the profiles. The increased soluble sodium in Pits 1 and 2 is partially due to the higher natural sodium bicarbonates in these soils from 30 inches downward. Therefore, elevated sodium ions have occurred to an approximate depth of 18 to 24 inches (Fig. 7). These data indicate an increase of approximately 30 mg/kg at 2 feet. Pits 1 and 2 had increased sodium concentrations below 4.0. Calcium and magnesium have also experienced increased concentrations in the surface 12 to 18 inches. There is little environmental concern for these two ions, as they will offset the detrimental impacts from sodium.

Background barium concentrations ranged between 91 and 396 mg/kg, with a general increase in concentration with depth (Table 4). Barium concentrations for the three cell pits were elevated for the surface 3 inches. This impact is expected because of the high barium concentrations in the wastes. Pits 2 and 3 generally had background barium concentrations below the 3-inch layer.

Zinc concentrations show no movement past the surface 3 inches (Table 4); zinc concentrations do increase with depth for all four profiles. This increase appears to be based on natural effects and is not related to the treatment cell operation. Mobility of zinc in soils is pH-dependent. It appears zinc has moved from the native surface soils, which are well leached and have pH values between 4.5 and 5.5 su. Zinc accumulated in the higher pH zones below 40 inches.

Table 4. Soil Barium and Zinc Concentrations.

	Barium (mg/L)				Zinc (mg/L)			
Depth	Pit 1	Pit 2	Pit 3	Bkgd	Pit 1	Pit 2	Pit 3	Bkgd
0-3	695	660	5,170	91	38	52	122	27
3-6	449	258	286	110	39	47	35	50
9-12	545	310	156	106	27	51	31	37
21-24	393	314	233	180	33	41	36	22
33-36	254	356	381	222	40	37	33	31
45-48	ND	213	222	289	96	50	50	31
57-60	171	171	208	396	98	65	59	80

ND - No Data

Physical Data -- Six soil samples, three each from Pit 2 and the background pit, were selected for physical analyses (Table 5). These six samples represented three separate depths for each pit. All six of these soils are classified as a silty clay.

The surface of the treatment cell (denoted as 18 to 24 inches in Table 5) has a bulk density of 1.82 g/cc, which reflects the compaction from the heavy equipment. Porosity for the Pit 2 samples ranged from 26.3% at the surface to 34.1% at 42 inches. The background porosity was fairly consistent, and ranged from 36.4 to 43.8%.

Characteristic moisture retentions were determined for these six soil samples (Table 5). The 1/3 bar retention moisture percent is important, as it generally represents the field capacity. Field capacity is defined as the percentage of water remaining after free drainage has practically ceased. Field moisture content the day of sampling for Pit 2 was between 22 and 26%, increasing with depth. The field moisture contents for Pit 2 were below the -1/3 bar moisture contents, indicating that no free drainage was occurring. (No moisture samples were collected in the background pit).

Table 5. Selected Soil Physical Properties.

Depth	Field	1/3 bar	1 bar	5 bar	15 bar	Bulk Density g/cc	Particle Density g/cc	Porosity
	----------% Moisture----------							
Soil Pit 2*								
18-24"	22.3	49.0	37.0	28.4	23.0	1.82	2.47	26.3
24-42"	25.0	33.5	26.6	20.0	17.4	1.67	2.53	34.0
42-64"	26.1	35.1	27.4	20.9	19.3	1.66	2.52	34.1
Background								
18-36"	ND	45.4	34.0	25.7	22.9	1.55	2.48	37.5
36-62"	ND	32.2	25.0	19.2	16.5	1.44	2.53	43.0
62-72"	ND	40.0	32.4	24.8	20.0	1.59	2.50	36.4

* 0-18" for Soil Pit 2 has been removed.

Characteristic moisture curves for each sample are presented in Figure 10. These curves are representative of clayey soils, with moisture contents ranging from 32 to 59% at field capacity to 16 to 23% for the wilting point (-15 bar). The surface soil in Cell 2 had a moisture content equivalent to -15 bar, while the two lower depth samples were between -1 and -5 bars. Since the treated NOW had been removed from Cell 2, the surface soil had dried due to exposure to sun and wind.

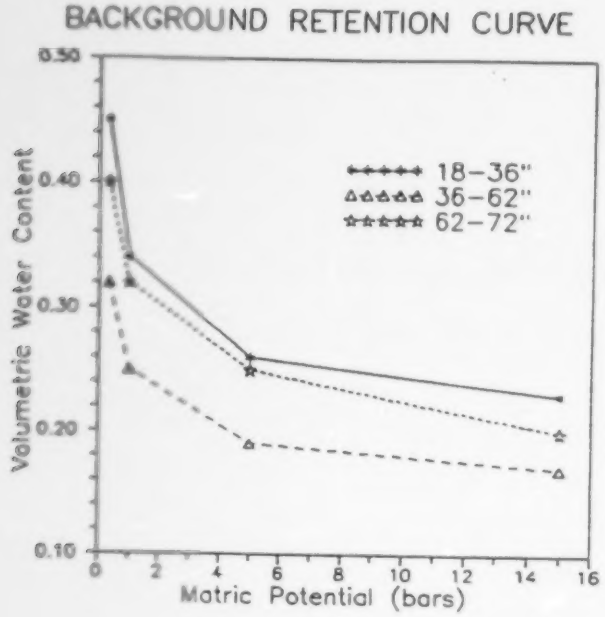
Discussion

The potential for environmental problems relating to land based treatment and disposal of wastes is based on environmental mobility of contaminants. Therefore, in evaluating a particular treatment and disposal operation, it is important to evaluate the water movement within that system. The results of this study indicate that the site specific soil conditions serve as barrier for contaminant migration. The saturated hydraulic conductivity (K_{sat}) for the Cell 2 subsoil averages 3×10^{-6} cm/sec. Since the field moisture for Cell 2 was below the -1/3 bar moisture content after the infiltration tests, the soils were not saturated. The background post-infiltration soil moistures averaged 44.7 and 42.0%, with the -1/3 bar moisture being 45.4%. Therefore, the background infiltration tests reached field capacity.

The infiltration tests for Cell 2 were actually evaluating unsaturated flow. The duration of the infiltration tests for Cell 2 were not sufficient to reach saturation and steady state. The appearance in the field of steady state K conditions was actually caused by reaching the lower limit of the instruments measurement capacity. Therefore, the K of Cell 2 would probably measure somewhat lower than the background, given long enough test using the sealed double-ring infiltrometer equipment. The unsaturated hydraulic conductivity is generally much lower than the saturated.

The low estimated water movement is supported by the soil chemical data. Chlorides, which are frequently used as a tracer for offsite contaminant movement, have moved vertically only about 18 inches in 5 years of operation.

Based on the current treatment cycle, which includes an application and dewatering cycle, these cells remain in a flooded or saturated condition for a minimum of 6 months out of the year. Thus, through 5 years of operation, Cell 2 has had a mixture of saturated and unsaturated conditions. Over this 5-year period, the impact of chlorides has reached approximately 18 inches. This equates to an annual saturated and unsaturated hydraulic conductivity of 3×10^{-7} cm/sec. This rate is near the hydraulic conductivity standard for soil liners at hazardous waste facilities (1×10^{-7} cm/sec). This is a very significant detail with regard to the potential



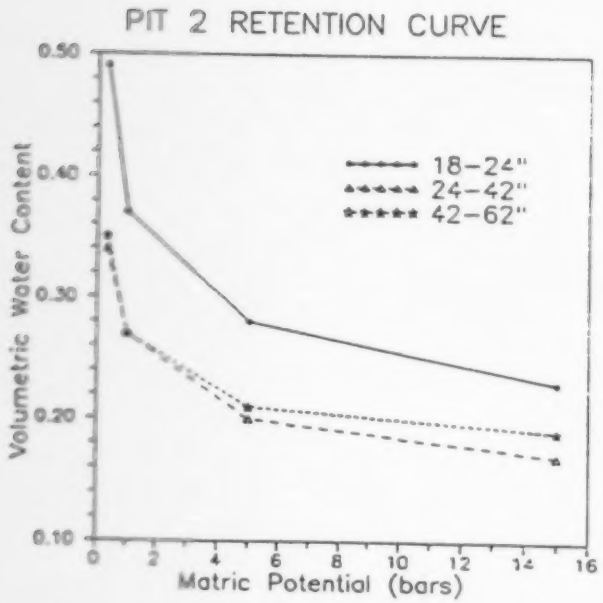


Figure 10. Characteristic Mositure Retention Curves for Pit 2 and Background Pit.

for migration to the shallow groundwater, as it also indicates that the actual water movement is much less than the measured saturated hydraulic conductivity.

The hydraulic conductivity measurements and the estimates of real water movement in this study support the low volume of soil-pore water collected from the treatment cells. At this site location, lysimeters may not be effective or needed for estimating the potential for contaminant movement; soil sampling should suffice.

Conclusions

The data collected from this study provides strong support for the current land treatment operations at CWC. The movement of water through and from the treatment zone in Cell 2, supported with data for the background soils, is very slow. This low water percolation through the treatment zone has resulted in very limited soluble salt migration. Based on this study, the environmental impacts resulting from 5 years of commercial land treatment of non-hazardous oilfield wastes have been minimal. From this study the following conclusions can be drawn:

- The impact of a dedicated, commercial facility must be weighed against the environmental impacts of scattered, unsupervised disposal.

- Site selection is a very important factor for a successful, dedicated, land treatment facility. Careful consideration must be given to both the soil/subsoil conditions and the local groundwater situation. This study demonstrates the benefits of a facility which was suitably located.

- This study also provides data which support the facility management strategy regarding barium. Even with the high concentrations which are managed at CWC, and with flooded conditions for up to 6 months at a time, barium has not migrated into the subsoil to any significant degree.

- Zinc, which is the second most prevalent heavy metal in the NOW managed at CWC, also has had limited vertical mobility. These two metals do not pose a threat to the environment as a result of the CWC Jennings operation.

- Based on this study, no changes to the current management at CWC were recommended. It is recommended that CWC periodically evaluate the subsoil conditions for soluble salt migration.

CLEAN-UP OF OIL CONTAMINATED SOLIDS

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Introduction

Oily waste, originating from a variety of coal/petroleum based industries, tailings produced during heavy oil recovery, or spills that may occur during oil production and transportation, presents a serious environmental problem.

To control the problem, various remediation technologies based on physical, chemical as well as biological principles have been developed and assessed. Application of any particular procedure has to be evaluated on an individual basis depending on the type and degree of contamination, its accessibility and cost-effectiveness.

The present paper describes an attractive novel process for treatment of oily waste materials, jointly developed by the Alberta Research Council (ARC) and the United States Electric Power Research Institute (EPRI) (1-4). The process utilizes coal as a contaminant collector, and is based on an agglomeration principle, with oily contaminants acting as the bridging liquid between coal particles. The effectiveness of the process depends on the ease with which the soil will release the contaminants and also on the contaminant affinity towards coal. In the process, the contaminated soil is mixed with a coal-water slurry. The products, in the form of contaminant wetted coal and cleaned soil are separated by flotation. Both attrition, which takes place during mixing, and sorption capacity of the coal are very important to process performance.

The potential of this process has been demonstrated through extensive batch experimental programs followed by verification in 6T/day pilot plant tests. A wide variety of oil contaminated soils have been evaluated with particular emphasis placed on remediation of soils from manufactured gas plant sites.

Description of Contaminated Samples

A number of contaminated soil samples were used in the evaluation studies of the clean-up process. A contaminant has been defined as any organic matter (solubles) which can be extracted with toluene or dichoromethane. On the basis of the origin of contaminant, the samples received represent soils contaminated with:

- tars produced by manufactured gas plants, "MGP"
- heavy oils, "HO"
- gasoline, diesel and residual fuel (oil spills), "OS"
- petrochemicals, "PC"

The composition of samples varied within a wide margin, with contaminant concentration ranging from less than 1 to 60%, Table 1. The toluene soluble contaminants displayed distinct variations in volatility. It can be seen that the contaminating species ranged from very light, fully distillable components (e.g. gasoline) to much heavier ones with about 60% non-distillable residue (e.g. heavy oil), Fig. 1. Volatility effects the viscosity which is an important factor in coal-bridging liquid interactions. Also there were differences in the chemical composition of contaminants. According to its thermal history, the tarry material extracted from MGP wastes was characterized by a high degree of unsaturation as indicated by the low atomic hydrogen to carbon (H/C) ratio of 0.85 vs. 1.46 of the heavy oil. In general, the lower H/C ratio, the higher concentration of aromatic hydrocarbons. The solids in contaminated samples varied from homogeneous, clay-like materials to heterogeneous materials with a wide particle size distribution that included pebbles, rocks and molten minerals, Table 2. Although the basic components of solids were silt and sand, some samples, MGP tar refuses in particular, contained considerable quantities of cokes and chars (up to 40%).

Process Description

The scheme of the ARC/EPRI process for clean-up of tar/oil contaminated soil is presented in Fig. 2. The process consists of two stages. In stage I, a suspension of contaminated soil and coal in water is subjected to tumbling in a specially designed drum at an elevated temperature and optimal solids concentration. The mixture is subsequently screened into two fractions: -1mm and +1mm. The -1mm fraction is subjected to conditioning and agloflotation which separates the coal flocs (microagglomerates) in the form of "froth 1" from clean (tar/oil free) tailings. Stage II is optional and depends on the initial response of the treated waste to the cleaning.

In stage II, the tailings from agloflotation are combined with a -1mm reject derived from selective grinding of +1mm fraction. The combined material is subjected to reprocessing in the presence of small quantities of coal and a suitable collector and again is subjected to agloflotation, thus giving rise to "froth 2" which, together with "froth 1", forms a combustible product. The tailings from reprocessing yield clean soil. During agloflotation, some feedstocks can produce middlings (solids with poor settling properties). Depending on the characteristics of the treated soil, the "middlings" are combined either with combustible product or clean soil.

Processing

The coal used in the experiments was pulverized to a top size of 0.6 mm. The quality of the product streams, in terms of contaminant concentration and ash content, was determined by extraction with dichloromethane, followed by proximate analysis of non-soluble solids.

The parameters investigated were temperature, contaminant/coal ratio, solids concentration, agitation and residence time. The effect of temperature on the clean-up of tar contaminated soil is shown in Fig. 3. The amount of coal required in the process depends on the origin and concentration of contaminant, and is higher in the case of oils than in tars, Table 3. The results of processing a number of contaminated samples, in terms of the residual contaminant retained in the soil, are shown in Table 4. Overall the contaminated soils responded well to the cleaning procedure with coal. Most samples were cleaned to satisfactory levels using the Stage I approach.

However, the ease with which the various samples can be processed depends to a large extent on the chemical and physical nature of the sample. Samples, MGP-7 and MGP-8, represent an extreme case of contaminated soils that were difficult to process. The tarry contaminant in these samples had a deleterious effect on the flotation of coal resulting in poor product separation. Moreover, the porous sintered material, char and coke present in the soil tended to retain the unacceptable high amounts of tar. In these cases, the separation process was greatly improved by addition of an appropriate froth collector in amounts of up to 2%, based on weight of coal matter. Increasing the addition of froth collector to 8% was needed to float the indigeneous tar loaded char/coke with a particle size up to 1.0 mm. To better clean the solids containing slag/char/coke with a particle size above 1.0 mm, grinding and reprocessing (Stage II) was required, Table 5.

In some instances, the presence of char/coke materials in the contaminated soil can be very advantageous to the clean-up process, as was the case of OS-1 sample. This soil was processed without any addition of coal by utilizing the carboniceous materials contaminating the sample. The sample responded very well to processing, yielding the soil with less than 0.1% residual oil at 81% soil recovery.

Essentially there is no upper limit for concentration of coal and/or petroleum derived pollutants in contaminated soil in terms of the efficiency of the clean-up process. A soil sample containing 50% (by weight) of a contaminant can be cleaned as efficiently as a sample which contains only 0.5-5% of contaminant concentration. Since however, the treatment requires the use of coal as an adsorbent in quantities 2-4 times greater as compared to contaminant concentration, it appears to be economically advantageous to treat samples characterized by rather low or intermediate (up to 10-12% by weight) contaminant concentrations. Low concentration of contaminants (0.5-5%) offers particular opportunities due to limited application of pyrolytic and combustion techniques for treatment of such samples.

The concentration of PAH in processed soil samples originating from MGP sites varied from about a few ppm to about 200 ppm. The concentration of PAH in clean samples from oil spills was below the detectivity level.

An interesting approach to the utilization of the ARC/EPRI clean-up technology is in the area of Alberta and Saskatchewan heavy oil/bitumen industry. Economics of these two provinces rely to some extent on their enormously rich, but low quality oil/bitumen deposits. Currently the recovery of oil/bitumen is being achieved by either mining and hot water separation or in-situ steam flooding, using natural gas for steam/power generation. It is apparent that these methods present a serious environmental hazard reflected in the vast accumulation of tailing ponds and oil spills. The adaptation of ARC/EPRI technology for the clean-up of contaminated ponds and spills using low cost, low quality coal and the utilization of this oil laden coal, instead of expensive natural gas for steam generation, offers a vary interesting route. Furthermore, the combustible product (oil adsorbed on coal) generated in the clean-up process can be either combusted or thermally treated, releasing light oil, which in turn can be used as diluent for pipelining heavy oil.

Conclusions

The process that utilizes coal for clean-up of oily/tarry contaminated soil can be applied to a variety of waste materials with a wide range of contaminant concentrations. The effectiveness of the process depends on the nature of both the contaminant and the solids.

Subject to state/provincial regulations and laws regarding the cleanliness of the product, the processed solids can be land filled either directly or after some additional treatment (ozone treatment, bio-treatment). The contaminant enriched coal can be used as a fuel in conventional coal fired power plants.

Based on the results obtained in the batch tests and in the 6T/day continuous unit, the conceptual engineering design of the 100T/day soil clean-up mobile unit has been prepared.

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TABLE 1
Composition of Contaminated Soil

Type of Contaminant	Sample	wt%		
		Toluene Solubles	Solids	Water
Tar	Tar Refuse[a]	1-60	20-93	4-54
Oil	Oil Spills	2-40	52-96	2-4
	Heavy Oil Sands	8-16	83-90	2
Petrochemicals	Industrial Waste	2-36	9-95	0-54

[a]MGP

TABLE 2
Particle Size Distribution of Selected Solids (%)

Particle size, mm	Description	Sample				
		MGP-6	MGP-7	HO-2	OS-1	OS-2
0.000-0.125	clay/silt	49.0	6.0	14.0	13.0	52.0
0.125-0.250	fine sand	51.0	15.3	83.4	11.5	20.0
0.250-0.500		-	20.1	1.6	14.2	10.0
0.500-1.000	medium sand	-	22.3	1.0	10.3	5.0
+1.000	coarse sand & gravel	-	36.3	-	51.0	13.0

TABLE 3
Contaminant/Coal Ratio

Contaminant Type	Ratio max
Tar	1:2.5
Oil	1:4

TABLE 4
Clean-up of Contaminated Soil
- Tar/Oil Concentration, wt%

Sample	Feed	Processed Soil
MGP-1[a]	8.6	0.07
MGP-2	1.2	0.00
MGP-3	5.4	0.29
MGP-4	1.6	0.20
MGP-5	66.9	0.10
MGP-6	0.7	0.10
MGP-7[a,b]	5.6	0.07
MGP-8[b]	10.6	0.17
HO-1	8.7	0.25
HO-2	15.2	0.04
OS-1[c]	0.5	0.04
OS(light)-1	2.0	0.17
OS(light)-2	0.5	0.03
OS-gasoline	3.1	0.06
OS-diesel	30.7	0.25
OS(heavy)-1	43.0	0.08
OS(heavy)-2	0.2	0.00
PC-1	34.3	0.01

[a] II stage processing
[b] froth collector required
[c] no coal required

TABLE 5
Clean-up of MGP-7 Sample
- Tar/Coke Concentration, wt%

Sample	Tar	Coke
as received	5.50	12.0
processed - Stage I[a]	0.60	5.0
processed - Stage I[b]	0.16	1.6
processed - Stage II[b]	0.07	0.7

[a] froth collector, 2% of coal
[b] froth collector, 8% of coal

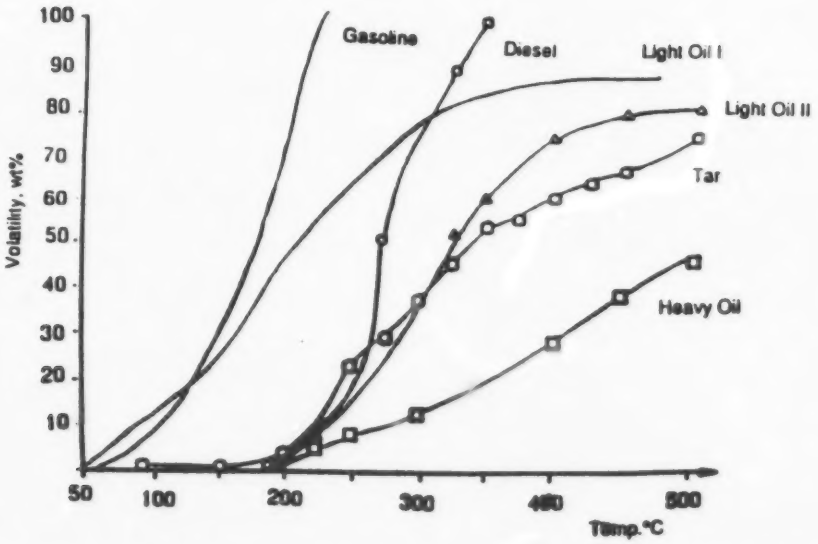

Fig. 1. Simulated Distillation Profile of Selected Contaminants

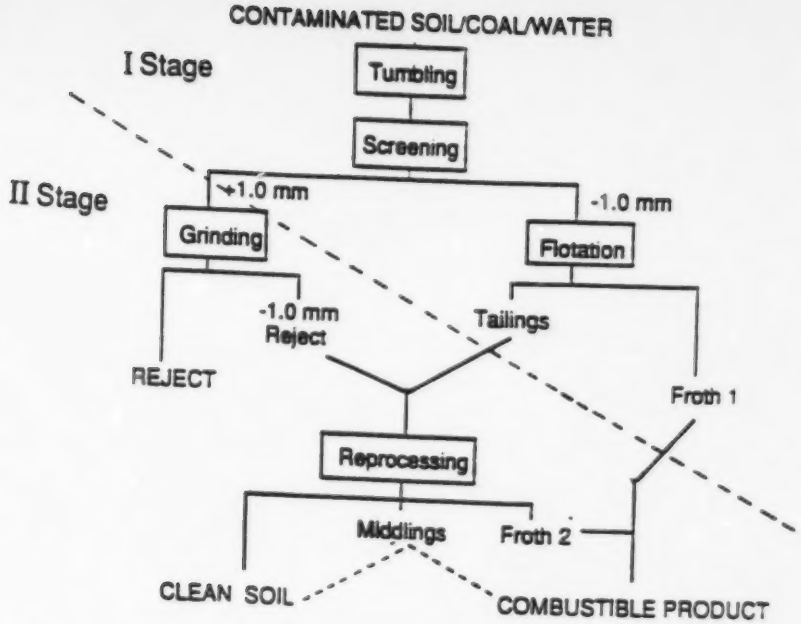

Fig. 2. Scheme of Processing Tar/Oil Contaminated Soil

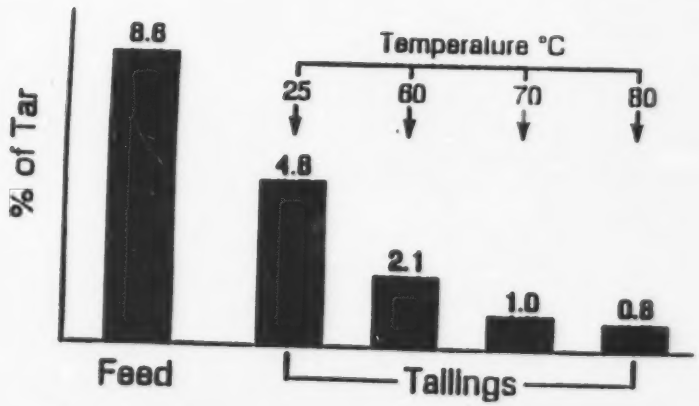

Fig. 3. Effect of Temperature on Clean-up

COMMON MISCONCEPTIONS ABOUT THE RCRA SUBTITLE C EXEMPTION FOR WASTES FROM CRUDE OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION

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Abstract

Certain wastes unique to the exploration, development and production of crude oil and natural gas have been exempted from federal regulation as hazardous wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA) in the United States. This regulatory exemption has been variously interpreted and sometimes mistakenly applied to wastes not covered by the exemption. This paper will explore the legal background of the RCRA exemption and clarify the Agency's interpretation of the scope of the exemption. It will also clarify the relationship of RCRA exempt wastes to CERCLA, as well as the differences among hazardous materials, hazardous wastes, solid wastes (non-hazardous wastes), and exempt wastes. Examples of common misconceptions of the scope of the exemption will be given. Recommendations and a brief overview of the legal requirements for the proper handling of both exempt and non-exempt wastes will also be touched upon.

Background

The Resource Conservation and Recovery Act (RCRA) was enacted by the United States Congress in 1976 and amended in 1980 and 1984. The objectives of this Act are to promote the protection of human health and the environment and to conserve valuable material and energy resources. To meet these objectives, RCRA provides for the promulgation of regulations/guidelines that assure wastes are managed in a manner that protects human health and the environment. RCRA also includes definitions of important terms, including "solid waste"; "hazardous waste"; and "disposal."

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* Opinions expressed in this paper are solely those of the author and do not necessarily represent those of the U.S. Environmental Protection Agency

The term "solid waste" as defined in RCRA, means any garbage, refuse, sludge from a waste treatment plant, water treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities, but does not include solid or dissolved material in domestic sewage, or solid or dissolved materials in irrigation return flows or industrial discharges which are point sources subject to permits under section 402 of the Federal Water Pollution Control Act.

The term "hazardous waste" as defined by RCRA means a solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical, or infectious characteristics may -

> (A) cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or
>
> (B) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed.

The term "disposal" means the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

Subtitle D of RCRA provides EPA the statutory authority to regulate the disposal of any solid waste. The regulations that have been promulgated under Subtitle D to date provide for state implementation and enforcement of state regulations that have been developed based upon certain minimum standards set by the federal government in Parts 256 and 257 of Title 40 of the U.S. Code of Federal Regulations (40 CFR). Although Subtitle D regulations specific to the oil and gas exploration and production industry have not yet been developed, RCRA does provide the clear statutory authority to do so.

Those solid wastes that are "hazardous wastes" are regulated under Subtitle C of RCRA. Subtitle C provides the statutory authority for federal regulations and their enforcement for the treatment, storage, and disposal of hazardous wastes. States may be authorized by EPA to operate their hazardous waste management programs in lieu of the Federal program if they demonstrate, among other things, that their programs are equivalent to, and no less stringent than, the federal regulatory program. Further

information about hazardous waste permits and state approval can be found in 40 CFR Parts 270 through 272.

In the RCRA amendments of 1980, Congress exempted certain wastes from regulation as hazardous wastes pending study by EPA, but the exemption did not change the statutory definition of hazardous waste. The Subtitle C regulations promulgated by the Agency, on the other hand, provide a second definition of hazardous wastes for the purposes of identifying which wastes are to be managed in accordance with the regulations. This regulatory definition, found in 40 CFR Part 261, is based upon the intent of the statutory definition and lists some specific wastes as hazardous, as well as identifies those parameters or "characteristics" that can be measured for the purpose of identifying a hazardous waste. The regulatory definition excludes those wastes identified as exempt from Subtitle C regulation. Specific regulatory requirements under Subtitle C include provisions for tracking the transport of hazardous wastes through the use of manifests, as well as requirements for ground water monitoring, corrective action, and the storage, treatment, and disposal of hazardous wastes (40 CFR Parts 260 - 268). For reasons discussed later in this paper, it is important to distinguish among the various definitions of "hazardous" wastes, materials and substances.

RCRA Exemption for Crude Oil and Natural Gas Wastes

One group of wastes exempted from regulation as hazardous wastes pending study by EPA (and a Report to Congress) are drilling fluids, produced water and other wastes associated with crude oil and natural gas and geothermal energy exploration, development, and production (see Section 3001(b)(2)(A) of RCRA). The Report to Congress was to be followed within six months by a determination by the Agency on whether regulation of these exempt wastes under Subtitle C was warranted. In preparing the Report to Congress, EPA was to evaluate seven study factors required in Section 8002(m) of RCRA. These study factors were:

(A) the sources and volume of such wastes
(B) present disposal practices
(C) potential danger to human health and the environment
(D) documented damage cases
(E) alternatives to current disposal methods
(F) the cost of such alternatives
(G) the impact of those alternatives on the industry.

In addition, the Agency was to study "the adequacy of means and measures currently employed by the oil and gas and geothermal drilling and production industry, Government agencies, and others to dispose of and utilize such wastes and to prevent or

substantially mitigate such adverse effects." The Agency took this study directive to mean that the Report to Congress should include an evaluation of the effectiveness of state and federal regulatory programs for the purposes of managing these wastes in lieu of Subtitle C regulation.

Following completion of the Report to Congress (1) in December 1987, the Agency held a series of public hearings and received public comment on the report. Based upon the findings in the Report to Congress and subsequent public comment, EPA published its regulatory determination in the Federal Register on July 6, 1988 (2), announcing that regulation under Subtitle C was not warranted for exempt wastes from crude oil, natural gas and geothermal energy exploration, development and production. However, the Agency did note that some regulatory gaps did exist, and committed to: (A) work with the states to improve their regulatory programs, (B) promulgate regulations under its Subtitle D authority specifically tailored to exploration and production waste management activities, and (C) work with Congress to develop any additional authorities that may be needed.

The Subtitle C exemption for these oil and gas wastes is directed at "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas." Included in the Report to Congress were EPA's tentative definition of the scope of the exemption based upon the statutory language and legislative history, and three criteria that EPA believes should be used to determine whether a waste is included within the exemption. Briefly, exempt wastes must be: 1) intrinsic to exploration, development or production activities; 2) uniquely associated with exploration, development or production activities; and 3) not generated as part of a transportation or manufacturing operation. These three criteria are spelled out in more detail on page II-18 of the Report to Congress. Also, in the regulatory determination, EPA presented a list (based upon the Report to Congress and public comment) of common examples of exempt and nonexempt wastes. For wastes not specifically identified in the regulatory determination, reference must be made to the three criteria in the Report to Congress to determine the status of a specific waste stream. Table 1 presents examples of exempt and nonexempt wastes listed in the regulatory determination.

Other Regulatory Programs

In addition to RCRA, other federal and state environmental statutes and regulations apply to oil and gas exploration and production wastes. The Subtitle C exemption does not negate the authority of these other statutes, but it may influence the way in which other statutes are applied towards the management of wastes from the

TABLE 1

Examples of RCRA Exempt and Non Exempt Oil and Gas Wastes *

EXEMPT WASTES	NON EXEMPT WASTES
Produced Water	Unused Fracturing Fluid/Acid
Drilling Fluids	Painting Waste
Drill Cuttings	Service Company Wastes
Rigwash	Refinery Wastes
Well Completion Fluids	Used Equipment Lubrication Oil
Workover Wastes	Used Hydraulic Oil
Gas Plant Dehydration Wastes	Waste Solvents
Gas Plant Sweetening Wastes	Waste Compressor Oil
Spent Filters and Backwash	Sanitary Wastes
Packing Fluids	Boiler Cleaning Wastes
Produced Sand	Incinerator Ash
Production Tank Bottoms	Laboratory Wastes
Gathering Line Pigging Wastes	Transportation Pipeline Wastes
Hydrocarbon-Bearing Soil	Pesticide Wastes
Waste Crude Oil From Primary Field Sites	Drums, Insulation, and Miscellaneous Solids

* Excerpted from the EPA Regulatory Determination

exploration, development, or production of crude oil or natural gas. These other authorities include the Underground Injection Control (UIC) regulations under the Safe Drinking Water Act, the National Pollutant Discharge Elimination System (NPDES) permit requirements under the Clean Water Act, the Department of Transportation regulations governing the transportation of "hazardous materials" (which may include products in addition to wastes), and various state statutes and regulations.

In addition, certain oil and gas wastes are also controlled under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) known as "Superfund." Because RCRA and CERCLA are closely related, it is important to remember that they are separate and distinct. While they may contain similar definitions and provisions, CERCLA is designed to mandate the clean-up of "hazardous substances" (which includes more than the universe of "hazardous wastes") by the parties responsible for their release. It should also be pointed out that, although there is a petroleum exemption under CERCLA, it is different than the RCRA exemption for exploration, development and production wastes. In particular, CERCLA Section 104 (a)(2) states that the terms "pollutant" or "contaminant" do "not include petroleum, including crude oil or any fraction thereof which is not otherwise specifically listed or designated as hazardous substances under section 101(14)(A) through (F) of this title, nor does it include natural gas, liquefied natural gas, or synthetic gas of pipeline quality." Section 101(14) of CERCLA also states "the term [hazardous substance] does not include petroleum, including crude oil or any fraction thereof which is not otherwise specifically listed or designated as a hazardous substance... and the term does not include natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel." The legislative history regarding the petroleum exclusion in CERCLA indicates that although petroleum and any fractions thereof are exempt, hazardous substances that may have been added to the oil, but which are not normally found in petroleum at the levels added, are not exempt. The source of the contamination, whether intentional addition of hazardous substances to the petroleum or addition of hazardous substances by the use of the petroleum, is not relevant to the applicability of the petroleum exclusion. Therefore, EPA may respond under CERCLA to releases of added hazardous substances. EPA may also respond under CERCLA to releases of non-petroleum hazardous substances (as defined under CERCLA) from exploration and production wastes. In fact, several oilfield waste disposal sites that accepted RCRA Subtitle C exempt wastes are now Superfund sites because these wastes were not managed in a way to prevent the release of hazardous substances, and the RCRA exemption does not relieve the operator of liability under CERCLA. Similarly, any

state requirements that oil field wastes be treated as hazardous wastes are independent of the RCRA exemption.

Common Misconceptions

Since the inception of the exemption for oil and gas exploration, development and production wastes under Subtitle C of RCRA, there has been confusion by both operators and state and federal regulators. Most of the misconceptions relative to the exemption can be divided into two groups: the first concerns the scope of the exemption, and the second concerns the inherent hazard of the wastes.

The first group of misconceptions relative to the scope of the exemption include the following: (A) All wastes onsite are exempt; (B) All service company wastes are exempt; (C) Unused products originally intended for oilfield use are exempt; and (D) Exempt wastes are CERCLA exempt. These misconceptions result from a lack of understanding of the intent and legal basis for the exemption. Congress intended to exempt from the burden of full Subtitle C regulation those wastes that are intrinsic to exploration, development, or production processes and that are generated at facilities employing these processes. The exemption was never intended to free operators from all forms of waste regulation, nor to exempt operators from liability in cases of mismanagement of the waste.

Not all wastes generated at an oilfield site are intrinsic to, or uniquely associated with, oil and gas exploration, development or production. The EPA Report to Congress provides three criteria that must be met in order for a waste to be considered exempt. It is important that a waste be both intrinsic to, and uniquely associated with, efforts to extract oil or natural gas. If a waste generated at an exploration or production site (other than a substance that has been used "down-hole" or produced from the well) is the same as a waste generated by a nonexempt industry (e.g., oil refining), then that particular waste is not unique to oil or gas exploration, development or production, and is, therefore, not exempt. Examples would be waste solvents used to clean tools and equipment, and waste crankcase and lubricating oils. Similarly, unused products that are to be discarded are not exempt because they were never intrinsically derived from the exploration, development or production of oil or gas within the meaning of the statute, regardless of the intent in preparing the product. Examples would include spilled chemicals, truck clean out wastes, and unused excess or off-specification products such as improperly formulated completion fluids. Finally, the RCRA Subtitle C exemption has limited bearing on the jurisdictional coverage of CERCLA, since these are two separate and distinct legal

authorities. Non exempt RCRA hazardous wastes are automatically hazardous substances under CERCLA, but some substances are hazardous under CERCLA for reasons other than being a hazardous waste. Some RCRA exempt wastes can be (and in fact already have been) contributing factors in the identification of Superfund sites. Therefore, improper management of RCRA exempt wastes may subject the operator to CERCLA.

The second group of misconceptions concerns the hazardousness of the exempt wastes. There are basically two common errors: (A) all exempt wastes are nonhazardous, and; (B) if small amounts of nonexempt hazardous wastes (by implication both listed and characteristic hazardous wastes) find their way into a large volume of exempt waste, the entire volume is designated as hazardous. The first misconception in this group arises from confusion over the intent and meaning of the exemption, while the second comes from the blanket application of the so-called mixture rule for listed hazardous wastes to characteristic hazardous wastes as well.

The regulatory definition of hazardous waste found in 40 CFR Sections 261.3 and 261.4 excludes "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy," but it does not change the wastes' basic nature, nor does it alter or change the statutory definitions of hazardous waste or hazardous substance found in RCRA and CERCLA. It would be more accurate to refer to these wastes as "RCRA exempt" instead of "nonhazardous" since an exempt waste may still exhibit hazardous characteristics even though it is not regulated as such under RCRA. The terms "hazardous waste," "hazardous substance" and "hazardous materials" are terms of art that have very specific statutory and regulatory definitions that may differ in the various authorities. The improper use of the terms "hazardous" and "nonhazardous" without clear reference to a specific statute or regulation can cause confusion over the status of a waste. This is an important concept since an exempt waste may still be considered hazardous under state hazardous waste laws, Department of Transportation regulations, or for the purpose of application of Superfund.

The so called "mixture rule," although not specifically an exempt waste issue, is also a source of confusion on the part of some operators. There are two types of nonexempt hazardous waste; listed and characteristic hazardous wastes. A listed hazardous waste is one from specific or non-specific sources which the Agency specifically listed in the RCRA regulations as hazardous. A listed hazardous waste is considered hazardous wherever it is generated and managed unless it has been specifically delisted by EPA; a characteristic hazardous waste is only hazardous when it exhibits one or more of the hazardous characteristics of toxicity,

reactivity, ignitability, and corrosivity as defined in 40 CFR sections 261.20 through 261.24. A non-listed waste stream may be either hazardous or nonhazardous depending upon its characteristics, as determined on a site-specific and time-specific basis. The mixture rule is applied differently to listed and characteristic hazardous wastes. Listed wastes are always hazardous (unless specifically delisted by EPA) and any mixture of a listed hazardous wastes and a nonhazardous or exempt waste is itself a hazardous waste regardless of the relative volumes of the wastes prior to mixing.

A mixture of a characteristic hazardous waste (other than by a small quantity generator as defined in the regulations) and a nonhazardous waste is only a hazardous waste if the resultant mixture also exhibits a hazardous characteristic. However, the act of mixing a characteristic hazardous waste with a nonhazardous or exempt waste to create a nonhazardous waste mixture is considered to be treatment of a hazardous waste and must be done in accordance with the appropriate RCRA requirements, including any necessary permits.

It can be seen that, although not every case of mixing a hazardous waste with exempt or nonhazardous wastes results in a hazardous waste mixture, significant legal and logistical problems can arise from co-disposal of exempt and nonexempt wastes.

Responsible Waste Management

The question may come to mind that, if some exempt wastes may still be inherently hazardous, then what does the exemption really do for the operator? The answer is simple: it frees the operator from the prescriptive measures of the federal Subtitle C regulations; rather, the operator is subject to Subtitle D and other existing federal and state authorities. While the standard for Subtitle D protection is the avoidance of a reasonable probability of adverse effects on health, this together with other laws and prudent management to avoid CERCLA liability suggest that there are still incentives for responsible waste management practices that are protective of human health and the environment. While the exemption lifts many of the burdens of Subtitle C requirements, it remains the operators' responsibility to assure adequate protection through proper waste management practices.

Responsible waste management practices may include such activities as waste segregation, waste minimization, recycling, compliance with applicable regulations and industry standards, prevention, mitigation and remediation of adverse impacts upon human health or the environment, and advance planning to identify and avoid actual or potential adverse impacts. In the United States, the American

Petroleum Institute (API) has taken the initiative in assisting operators in managing their wastes by issuing an API Environmental Guidance Document that outlines applicable regulations and industry standards for various waste management practices (3). This first edition is now in the process of being revised and updated.

Conclusion

The RCRA exemption for certain oilfield wastes is a legal statement (in the RCRA Amendments of 1980) that excludes certain defined wastes from the requirements of RCRA Subtitle C. This exclusion, in and of itself, does not make any judgment on the inherent hazard of the wastes in question. It does not change the chemistry of the wastes, nor does it relieve the waste generator or disposer from the responsibility of handling and disposing of the wastes in a prudent manner. The exemption only gives the operator the ability to select a disposal option other than full Subtitle C requirements for what might otherwise be a hazardous waste; however, it should be noted that the selected option must still be in compliance with other existing authorities. Prudent managers of some exempt wastes often elect to go beyond the minimum legal requirements.

As mentioned above, the exemption makes no legal finding on the inherent hazardousness of the wastes, and the RCRA-exempted wastes are not automatically exempt from Superfund or other legal authorities. An operator may elect to dispose of his wastes at a Subtitle C permitted facility if he believes that the inherent hazard of the waste requires that level of protection for the environment. However, if the operator believes that another waste disposal option provides sufficient protection for the environment, he is free to use that option. But in either case, the operator may be held liable for his action if damages occur. Prudent waste management makes good sense for several reasons: to avoid future liability costs, to promote good public relations, and to lessen the need for more prescriptive state and federal regulations.

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COMPREHENSIVE ENVIRONMENTAL TRAINING PROGRAM FOR THE PRODUCTION OF OIL AND NATURAL GAS INDUSTRY

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Abstract

Environmental rules and regulations are on the increase worldwide. The United States, the apparent leader in environmental requirements, have increase the number of requirements imposed on industry, increased the enforcement of these requirements, and have increased the personal liabilities of employees. Not only the United States but such international countries, as Norway, Saudi Arabia, U.K., and New Zealand all are requiring more and more attention be given to environmental concerns.

Because of this concern it is imperative Amoco employees are properly trained in the field of environmental protection. Not only because it's the law, but Amoco's own internal requirements specify that we operate with a "standard of care" throughout our worldwide endeavors.

Amoco Production Company has made a commitment to developing a comprehensive environmental training program that gives the employees the tools needed to make intelligent decisions.

We divided the training program into three phases corresponding to the three levels of employees within Amoco Production, (i.e. Managers, Engineers, and Field Personnel). Each phase requires its own unique level of understanding of the environmental requirements. For example, on one end of the spectrum the managers need a broad understanding of the regulations. Where as on the other end the field personnel would need a more detailed comprehension of the law. In order to develop a strong foundation within Amoco, we have directed our phase I at the field personnel followed by the engineers for phase II and finishing with management as phase III.

The program will stress the legal requirements as will as potential environmental impacts to oil and gas operations. The key is to recognize when a requirement is applicable to your operations. The training will be in a modular form consisting of a video tape, student manual, and a teachers manual. There will be approximately 10 modules for phase I. Each module will range from 2-4 hours to complete. They will include pre-testing, problem solving associated with the video, and a review. Each module is self contained and could be sent to any location for training.

We expect this program to result in developing a higher level of understanding of environmental rules and regulations by our field employees throughout Amoco Production Company, and standardizing, if you will, the training employees receive for environmental concerns. It will create an atmosphere of compliance among the employees as well as demonstrate Amoco's commitment to the protection of the environment. Finally it has the

potential to be used in the development of a standard of care and good operation practices worldwide.

Objective

The objective of this project was to develop a comprehensive training program on Environmental requirements, including both the legal obligations as well as Amoco's own environmental policy and procedural requirements.

Within the last 20 years, the United States has increased its legislation for environmental protection. These legislative acts require certain governmental agencies to develop extensive rules and regulations which in turns creates an ever increasing burden on industry to understand and comply with the law. These rules are usually very comprehensive and difficult to read. Normal practice is to "weed-through" volumes of regulations to find that one section or part of a section that directly applies to our industry. This can be a monumental task involving regulations dealing with issues such as clean air, clean water, or hazardous waste.

For each one of these statutes the government has established penalties for violation of the law. In the past, these fines and penalties constituted nothing more than a "slap on the hand". However, as these laws become amended, the government has increased the penalties to include substantial fines for companies as well as criminal penalties for individuals. These penalties place heavy emphasis on the fact that our employees must be well trained in their legal obligation to protect the environment. With this increase in penalties, agencies have also increased the enforcement of these requirements. For example, from the time the United States enacted its first pollution control statute in 1899 until 1980, only 15 environmental crimes were prosecuted, averaging fewer than 2 per decade. Plus, all of these cases were misdemeanors resulting in average fines of only $50 to $100. On the other hand, over the last nine years, there has been a dramatic increase in federal enforcement. Since 1982, the courts have handed down more than 400 convictions. As of May, of 1988, judges have imposed more than $23 million dollars in fines and sentenced individuals to a cumulative imprisonment time of more than 250 years.

Therefore, compliance is critical for a company to operate in todays environment. It's vital for the person in the field to be adequately trained to understand his/her obligation to protect the environment they live and work in.

Training Requirements

In order to establish the training requirements two questions had to first be answered: 1) Who are the recipients of this training and 2) what is the information the employees have to know?

The recipients for environmental training can be divided into three categories:

1. Management
2. Engineers
3. Field Foremen & Field Environmental Specialist

Management

Management officials have the authority over various operations within the company. The ultimate responsibility for these operations lies on his/her shoulders. If a violation of an environmental law occurs at a facility under his/her control, he personally can be held liable for the crime. Even though he was not personally involved in the violation and was unaware of what was going on, he should have known and was in a position to stop the action. This is the way U.S. Environmental law is interpreted.

Therefore, management needs some form of basic or generalized environmental training. An overview covering the key elements of the law and a reminder of Amoco's Environmental Policies should be sufficient.

Engineers

The key role of an engineer is in the design of new operations, facilities, and experimental functions, (i.e. research and development). In designing a brand new facility or revamping an old one, the engineer must be constantly aware of environmental concerns. For example, air emissions from stacks, water discharges from pipes, or hazardous waste by-products from various process. Even something as simple as moving locations could make a difference. The engineer needs a more in-depth understanding of the impact industry has on the environment and how simple considerations up front in the planning stages can prove to benefit the company economically, while providing environmentally sound result. The engineer also needs to know that certain actions may require extensive permitting by the government, and planning for these must be done early in the program.

In the area of research and development, newer and better chemicals are constantly being developed to help in the production of crude oil. Because of these exotic chemicals, there are potentials for harm to human health and the environment. Even though they may work better, the potential liability may be to great for the company. As a result, the training for engineers should provide a more comprehensive understanding of environmental requirements and the effects of pollution on the environment.

Field Foremen & Field Environmental Specialists

Field foremen and field environmental specialists are the people "in the trenches." The daily compliance of environmental laws and Amoco Policies is entirely in their hands. They must complete permit applications, perform monitoring and sampling, and be constantly on the alert for potential problems. They also have a more direct contact with government agencies. The first line of compliance is in the field. These people need to have the best understanding of all on environmental requirements that affect their operations. Therefore, an in-depth, comprehensive training program is vital for field personnel.

Amoco has never before embarked on an environmental training program of this magnitude. Because of this, Amoco has decided to use a phased-in approach. The first group to receive this extensive training will be the field personnel. This will start the development of a strong foundation for Amoco's compliance. The second phase will

concentrate on training for the engineers and finally the third phase on managers. As Amoco develops it's standard of care worldwide training on environmental concerns will reach to every Amoco operations.

Evaluation of Existing Courses

First, a review of existing environmental training course was made. Amoco consulted various publications, interviewed other major oil companies and contacted various educational institutions. All available courses were eliminated for various reasons. Most were too general in scope or not specific enough to the oil industry. Others were screened out because of excessive emphasis on academic training methods with minimal trainee participation, or excessive emphasis on promotion of company products and services throughout the training. Overall, none of the courses reviewed fit the specific needs of Amoco. It was decided at this point to develop a course to fit our own needs.

Designing of Training Curriculum and Courses

Since our own environmental training program would be initially directed toward Amoco's field personnel, we had to first determine exactly what the field personnel needed to know. The production of crude oil and natural gas encompasses a portion of every environmental law on the books today. Each law covers the spectrum of environmental protection and pollution control. Each law has specific areas of compliance for the oil production industry. Collecting this information and applying it in a manner understandable to field personnel was quite a job. It was decided to take each statute and break it down to the basics so that field personnel could answer the simple questions of who, what, when, where, and how.

1. Who is responsible for compliance?
2. When do the requirements apply to me?
3. What are the requirements I have to comply?
4. Where do I go for help?
5. How do these regulation affect me personally?

If a trainee can answer these basic questions regarding each statute, he will satisfy the course objectives. It was decided to divide the requirements up into individual training modules. Ten training topics have been identified for the field personnel. Each module will consist of a video, student workbook, and an instructor's manual.

Video

The video will be divided into three segments, 1) a general overview, 2) report or permitting completion, and 3) a review. Each segment will run five to ten minutes on the average. The general overview will introduce the topic and will be presented in one of several formats. For example, one format might use dialog between two individuals to establish a particular topic, while another format may use a narrator to walk the student through a topic.

The second segment would walk the students through any paperwork requirement associated with that particular topic. For example the module on water discharge would include how to complete a discharge monitoring report.

Finally the third segment would be a brief review of what the student has learned in the previous two segments and the class.

Student Workbook

Each workbook will consist of:

1. Pre-Questionnaire
2. Requirements of the topic as it applies to production operations.
3. Copies of all forms and/or permits
4. Post-questionnaire

The pre-questionnaire acts as a benchmark for the instructor to identify the extent of knowledge the trainee has for the subject prior to the video. This is not designed to embarrass the student, but merely to help the instructor design the course to fit the needs of the class. The workbook also will have the specific requirements for the topic as it relates to the production of crude oil and natural gas. This eliminates the trainee from having to review volumes of regulations looking for that one section that applies to him. All of this has been done for the student making a quick and easy reference for future work.

All forms or permits associated with the topic will also be included. One set will be completed as an example with an explanation for each blank on the opposite page. Also a blank copy will be included that can be copied for future work. Finally a post-questionnaire will be included as a means for the instructor to compare questionnaires and determine if the message is getting across so he can adjust the training accordingly. The following is a brief description of the 14 modules:

1. Department of Transportation (DOT) - Describes the requirements of shipping hazardous materials to and from our field locations. Also discusses the proper paper work involved in transporting hazardous materials.

2. Spill Prevention Control and Countermeasures (SPCC) for On-shore - Describes the specific requirements of preemptive measures to reduce the likelihood of an oil spill. This also includes the recommended forms to help standardize Amoco operations.

3. 404 Permitting - Refers to section 404 of the Clean Water Act requiring permitting for dredge or fill work. For example, permitting is required if you place a drilling platform in wetlands.

4. Groundwater - Presents specific requirements that must be followed to insure protection of underground aquifers. Also includes groundwater monitoring and cleanup.

5. Prevention of Significant Deterioration (PSD) - Focus on air emissions. The concerns, for example would be what can you emit, how much, and when does it apply.

6. Hazardous Waste - Describes the characteristics of hazardous waste, and the handling of waste from generation to ultimate disposal.

7. Comprehensive Environmental Response Compensation Liability Act (CERCLA) - Identifies chemicals considered to be hazardous in your operation and advises how to properly report any spillage of these chemicals.

8. Superfund Amendment Reauthorization Act (SARA) - Applies to the general public's right to access information dealing with hazardous chemicals on your facility. There is a considerable amount of paperwork associated with SARA and failure to report properly carries significant penalties.

9. National Pollution Discharge Elimination System (NPDES) for on-shore - Describes the permitting and regular testing for process water discharged into waters of the U.S. Also includes an introduction to bio-monitoring. As well as extensive permitting and recordkeeping.

10. National Pollution Discharge Elimination System (NPDES) for off-shore - Is the same as onshore however bio-monitoring is the key element for offshore compliance.

Program Implementation

The following methods were considered for the implementation of this program: central training facility, traveling instructor, correspondence training, or audio-visual training packages.

In choosing the most appropriate approach, consideration was given to time, group size, and audience. For example it would be difficult to bring all field personnel into a central training facility. Therefore, each module was designed to be self- sufficient. The video, student workbook, and instructor guide can be sent to a field location and taught to a small group by either a person in the field or a traveling instructor. As the training program expands to include engineers and managers, other approaches may prove to be more appropriate.

Each module will be designed to create as much active participation as possible, by developing small work groups within the class for common problem solving.

Results of Training

If this program is developed as planned, I see it having a very positive impact an Amoco. It will formalize Amoco's training while increasing the knowledge and awareness of all Amoco employees. By providing a better understanding of pollution control, it will create an atmosphere of compliance from top management down to the field personnel. It will also demonstrate the commitment Amoco is taking to protect the environment and its employees.

Finally it will develop a standard of care and operating practices that can be utilized throughout Amoco's world wide operations. Even in areas that may not have as extensive legal requirements as in the United States we can still operate in a method that will give high priority to the protection of our environment as well as our employees.

CONTAMINATED SULPHUR RECOVERY BY FROTH FLOTATION

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INTRODUCTION

In order to recover the sulphur from contaminated sulphur base pad, Husky Oil Operations Ltd. utilizes a froth flotation process at the Ram River gas plant located in West Central Alberta, approximately 250 Km from Calgary [Fig. 1 - Alberta map]. Ram River is one of the largest gas processing plant in North America for the production of sulphur from sour gas. The sour gas plant capacity is 17,700,000 m^3/day with a hydrogen sulphide content of between 10 - 35%. The maximum sulphur plant production is 4,600 metric tonnes [t]/day.

SULPHUR BASE PAD DESCRIPTION

Background and History

The froth flotation process in this case was conceived to reclaim the base pads of sulphur blocks scattered throughout the sulphur industry in Alberta and in similar conditions world-wide(1,2). These sulphur blocks were formed during the 1950's, 60's and 70's when sulphur markets were poor and sulphur was generally regarded as an unwanted by-product of oil and gas processing. As a result, the sulphur was poured directly onto the ground, forming the foundation or "base pad" for large storage blocks. A schematic cross-section of a typical base pad/sulphur block is shown in Fig. 2. The contaminated area of interface between the high grade elemental sulphur product and the underlying gravel and soil contains a substantial amount of valuable elemental sulphur.

During the 1980's with the improvement of sulphur markets, the high grade elemental sulphur product overlying the base pads has been re-melted to meet market demands. However, the sulphur base pads and other contaminated elemental sulphur rejects from industrial handling have proven difficult to reclaim, leaving hundreds of thousands of tonnes of contaminated sulphur throughout Alberta which are environmentally undesirable. Currently, it is estimated that between 600,000 and 1,000,000 t of contaminated sulphur exist in Alberta with about 300,000 t being located at Husky's Ram River Gas Plant. Not only are the base pads themselves an environmental problem, but moisture precipitation on the sulphur blocks and base pads forms an acidic water run-off that must be collected, treated and disposed of in a controlled manner to protect the environment. Although contaminated sulphur base pads were the primary reclamation target of the froth flotation facility,

additional material containing valuable elemental sulphur has accumulated at other locations throughout Alberta and is also targeted for processing.

Typical Composition

When the sulphur was poured directly onto the ground the molten elemental sulphur intermingled and solidified in the soil, creating physical bonds and contaminating the sulphur with organic impurities such as humus, wood, leaves and other vegetation and with inorganic impurities including fine clays, sand, pebbles and gravel.

At Ram River gas plant the base pad contains sulphur in the range of 80%. In other sulphur base pads in Alberta, the sulphur content could vary from 30 to 90% plus.

RESEARCH AND DEVELOPMENT (R&D) OF THE SULPHUR BASE PAD RECOVERY PROCESS BY FROTH FLOTATION

The process of sulphur recovery from contaminated sulphur products has been investigated by the industry for a number of years. Primarily, hot processes have been applied to melt the contaminated sulphur followed by filtration or separation by gravity for contaminant removal. The hot remelt and filtration processes have drawbacks related mainly to filter plugging. Due to fouling of the heat transfer surfaces by the contaminants the efficiency of the process is decreased. In addition, a waste product commonly called "sulphur crete", containing up to 80% sulphur, is produced. These hot processes have difficulties in handling sulphur base pad where the contamination exceeds 10% and because of rapid fouling of heat transfer surfaces and filter plugging, efficiency could be reduced when the contamination is as low as 5%. For processing of an average sulphur base pad containing 20% contaminants, the hot remelt and filtration method would only recover approximately 75% of the sulphur base pad feed. "Sulphur crete" tailings would typically contain about 50% sulphur by weight and would require treatment and disposal which is both expensive and a potential environmental hazard. Current practice involves hauling tailings to a landfill and treating with three parts limestone for each part sulphur to neutralize acidity.

A number of institutions, including Alberta Sulphur Research (ASR) from Calgary, have studied sulphur base pad recovery processes. According to ASR, elements of their sulphur base pad recovery processes have been applied to sulphur clean-up in Western Canada.

At the Ram River gas plant, a hot contaminated sulphur recovery pilot system was studied, constructed, operated, evaluated and shut down. This system had operational problems due to fouling of the heat transfer surfaces. The maximum remelt rate achieved was 2.8 t/h over a period of two hours. The filter screens required frequent cleaning. The system produced the unprocessable by-product "sulphur crete". The sulphur content of this by-product was analyzed and found to contain 40 - 60% sulphur. The process

was discontinued when operating costs could not be lowered below the economic threshold.

Hot processes have the disadvantage of producing organic combinations with sulphur which are objectionable and difficult to minimize or eliminate. Carsul, which can result from the reaction of sulphur and hydrocarbons poses problems in sulphur discolouration and in deposition phenomena which can result in plugging of filtration elements or of other restricted flow areas such as, orifices and spray nozzles(3).

Additionally, non-hot remelting processes have been investigated by the industry, such as:
- solvent extraction in which elemental sulphur is taken into solution with a solvent;
- burning the contaminated elemental sulphur to SO_2 for injection to a Claus recovery plant; however, the contaminant combustion products could adversely affect the recovery plant catalyst;
- use of two immiscible liquids which differentiate between sulphur and its contaminants by differences in density and wettability.

The above-mentioned "cold" processes have not yet been commercially applied in the oil and gas industry.

Due to the problems associated with the above mentioned contaminated sulphur recovery processes, alternative methods, including froth flotation, were deemed necessary to be researched.

The froth flotation process was originally developed in the mining industry. This process has not been applied commercially in the oil and gas industry for the sulphur base pad contaminated sulphur recovery prior to 1984 when our main froth flotation R and D activities started.

Following laboratory testing and experimentation, a process flow sheet for a froth flotation plant was prepared. The following phases illustrate the evolution of the process:

- R and D studies and froth flotation laboratory tests: December 1984 - December 1985

- Design by Wright Engineers Ltd. Vancouver, British Columbia, Canada and construction of the froth flotation plant based on R and D data: 1986 - 1987; plant start-up: May 1987.

- Patent granted in Canada in June 1987(1)

- Patent granted in United States in October 1989(2)

Froth Flotation Laboratory Tests Overview

Numerous froth flotation laboratory tests were planned and conducted varying parameters, such as: particle size, flotation time, reagent types and quantities, conditioning, slurry dilution, pH and temperature control.

Typical laboratory results, using Ram River sulphur base pad samples, are shown in Table 1.

The feed to flotation laboratory tests was prepared by size reduction and screening to -10 mesh, followed by conditioning with reagents. Typically the following reagents were used:

- Frother: methyl isobutyl carbinol [MIBC]: in the order of 0.08 to 0.5 lb per short ton of dry raw material treated;

- Promoter/collector: kerosene or fuel oil in the order of 0.05 to 0.5 lbs per short ton of dry raw material treated.

In general, three stages of flotation were used: a first rougher stage and two stages of cleaning with a duration of approximately 15 minutes for the first stage and approximately 7.5 minutes for each cleaning stage. The reagents were used in the conditioning and rougher stage.

Comparison of Froth Flotation with Other Alternatives Applied by the Industry

Figure 3 provides an comparison example of the froth flotation versus hot remelt and landfill disposal for Ram River conditions. The froth flotation process compared with hot remelting appears to be superior both from an environmental and economic standpoint, primarily due to its higher recoveries [98% vs 75%] and lower sulphur content tailings [7.5% vs 50.3%]. As mentioned previously, the hot remelt tailings normally would have to be hauled to a landfill and neutralized with limestone. Due to the much lower sulphur content of the froth flotation tailings, research is ongoing to place the tailings on the reclaimed base pad area, treat them with an appropriate amount of limestone and mix with the top soil for revegetation. Also, research is currently being conducted on the reclamation of sulphur rich tailings through test plot and greenhouse experimentation.

The Ram River example presented in Fig. 3 is a base pad containing in average 20% contaminants which could be considered a typical value. It is not uncommon, however, to encounter base pads with higher levels of contamination. This can cause problems with the hot remelt system, as mentioned previously, due to fouling of heat transfer surfaces and filter plugging resulting in large reductions in overall efficiency and hence lower sulphur recoveries and higher sulphur losses in tailings. The froth flotation process, on the other hand, is capable of coping with higher quantities of contaminants in the feed material.

A possible third alternative as shown in Fig. 3, is simple disposal of the sulphur base pad in landfills. Although this does not result in any sulphur recovery, it may be necessary in cases where the application of recovery processes is not possible due to small base pad quantities, remote location or the presence of unprocessable contaminants. Disposal involves, as mentioned previously, treating the sulphur with limestone to neutralize acidity and disposing at a landfill site. This is the least desirable option, both environmentally and economically, but may be the only

alternative in difficult situations.

RAM RIVER FROTH FLOTATION SULPHUR RECOVERY PLANT DESCRIPTION

The simplified process flowsheets presented in Figs. 4 and 5 illustrate the overall process utilized at the Ram River froth flotation plant. Figure 4 shows the front-end size reduction and classification circuit while Fig. 5 presents the sulphur flotation circuits resulting in the final sulphur cake product. Each of the major components of the process will be briefly described with reference to Figs. 4 and 5.

Size Reduction and Classification [Fig. 4]

The contaminated sulphur base pad material is reclaimed by a scraper in combination with a front-end loader and placed into a large hopper with 6 inch openings for a preliminary screening. Large elemental sulphur chunks, being very friable in nature, can be broken through the hopper openings. Pieces of stone and other non-sulphur material, such as metal or large pieces of wood, will remain on the hopper and be removed to waste. Hopper undersize is collected and passed to a feeder belt, which discharges the material onto the feed conveyor. The feed rate is monitored by a weigh-scale located under the feed conveyor.

Raw feed less than 6 inches in size is conveyed to a rotary scrubber where elemental sulphur and contaminants are tumbled with water to break down the more friable sulphur lumps. The rotary scrubber product is screened through a 1/2 inch trommel screen on the rotary scrubber discharge. Oversize waste material containing particles larger than 1/2 inch is discharged to a debris pile, while undersize particles less than 1/2 inch flow into a spiral classifier for classification and densification.

As feed enters the spiral classifier, the coarse particles begin to settle to the bottom of the inclined vessel. The fine particles, less than 10 mesh in size, are contained in the overflow which is discharged at the lower-end of the classifier. The coarse particles that have settled in the tank settling zone are conveyed to the upper-end of the vessel by a rotating spiral screw at a rate slow enough to allow liquid drainage down to the lower-end and prevent excessive slurry agitation. The coarse particles are then fed to the attrition scrubber.

Attrition scrubbing is the process of forcing particles within a slurry to impact and abrade against each other. It is used to remove film or coatings from particles to increase the efficiency of the next step in the circuit, the flotation process. This cleaning or polishing of the sulphur particles increases the likelihood that the air bubbles will float the sulphur particles. The particles are given momentum by two propellers driven at opposing pitch, which force the particles against each other at a velocity that causes abrasion. Some particle size reduction occurs but this is less significant than the actual particle cleaning.

The discharge from the attrition scrubber and the fines overflow of the spiral classifier are combined and pumped to the 10 mesh vibrating screen. The undersize of the 10 mesh screen is circulated to the conditioning tank ahead of the flotation circuit. The oversize of the 10 mesh screen is normally directed to the spiral classifier feed.

Conditioning and Flotation Circuits [Fig. 5]

The undersize of the vibrating screen flows by gravity to the conditioner tank where the flotation reagents MIBC and kerosene or fuel oil are added, to aid in the flotation of the sulphur particles. After mixing in the conditioning tank the slurry flows to the rougher flotation cells. The froth flotation circuit is composed of three stages: the 6 cell rougher stage, the 3 cell cleaner stage, and the 3 cell recleaner stage.

A typical flotation cell process is illustrated in a schematic cross-section presented in Fig. 6. The cage-like rotor draws air through the annular space between the standpipe and the shaft. The air is mixed with the slurry, forming air bubbles. MIBC, which is a frother, reduces the surface tension of the water enhancing the formation of finely divided air bubbles. In this manner, the sulphur particles collide with and attach themselves to the air bubbles and float to the surface. The sulphur flotation is also aided by kerosene or fuel oil which is a promoter/collector that coats or films the coarse sulphur particles making their surfaces more non-wettable which helps them float.

As the slurry flows through the 6 cell rougher flotation circuit, the sulphur particles floated by the air bubbles form a froth at the surface of the flotation cells which is skimmed off and pumped to the first stage 3 cell cleaner. The impurities and contaminants are carried through the lower zone of the rougher cells and are pumped to the tailings circuit.

The sulphur product flows through the 3 cell cleaner and additional sulphur is floated, skimmed and pumped to the 3 cell recleaner. The slurry which remains in the cleaner cells still contains valuable sulphur and is recirculated back to the conditioner tank [referred to as middlings or midds No. 1] for reprocessing through the rougher flotation circuit. The final flotation product that is skimmed off from the 3 cell recleaner is pumped to the vacuum belt filter for de-watering.

The flotation froth coming from the 3 cell recleaner contains approximately 40% solids [60% water]. The resulting sulphur cake is the final product of the froth flotation plant. This product is de-watered in a horizontal vacuum belt filter down to 15% moisture or less. The filtrate water recovered by vacuum filtration is recycled back to the water circuit for re-use.

The tailings from the 6 cell rougher flotation stage are sent to a de-aerator tank followed by a thickener tank for densifying before filtration. The water recovered in the thickener tank overflow is collected in a reclaim water tank and recycled to the front-end of the plant. Actually, over 95% of the process water is re-cycled with only minimal amounts of make-up water

required to compensate for the water lost in the sulphur concentrate and tailings filter cake. As a result, environmental water disposal problems typically associated with a large water make-up are virtually eliminated in Ram River froth flotation plant.

The tailings thickener tank underflow, which is made-up of settled and flocculated solids with approximately 60% water content, is pumped to the squeeze belt filter for further water removal down to 25 - 30% or less.

RAM RIVER FROTH FLOTATION CONTAMINATED SULPHUR RECOVERY PLANT PERFORMANCE

Since the plant's start-up in May 1987, ongoing efforts have been directed at optimizing the plant performance in order to reach the design capacity of 18.8 [t/h] with maximum recoveries and purities and minimum amounts of sulphur in the tailings. It should be noted that the froth flotation of contaminated sulphur represented a new application of this technology and that previous operating experience was not available to use as a guideline. Therefore, initial energies were concentrated on achieving satisfactory plant operating characteristics. After the initial start-up period, plant operations staff began to rectify many of the mechanical problems and production rates of 6-8 t/h were achieved with sulphur purities of approximately 98.5 - 99%S, sulphur recoveries of about 95% and tailings sulphur contents in the 15-20% range. These values were better than those of the hot remelting process, but additional improvements were possible. Through a series of plant enhancements, mechanical process problems were corrected and performance has improved. Currently, the froth flotation plant is capable of processing approximately 18 t/h of plant feed with a typical final product purity of 98.5 - 99%S with potential to be increased up to 99.6%S. Sulphur recoveries of approximately 98% and higher and tailings sulphur contents in the order of 10% or less have been achieved. Additional process enhancements are still being implemented and fine-tuned and it is anticipated that the plant performance can be further optimized and improved in the near future.

POSSIBLE FROTH FLOTATION PLANT EXPANSION

In addition to sulphur base pad recovery by froth flotation, another processing scheme is patented. This scheme is related to the treatment of "sulphur crete", the waste residue formed through hot remelting which, until now has been considered unprocessable. The processing of "sulphur crete" is a combined method using the present plant along with a fine grinding stage in which 5% "sulphur crete" is blended with 95% base pad material as shown in Fig. 7. This process has the advantage of using all the present froth flotation plant equipment plus the addition of a small fine grinding circuit [less than 1 t/h] for the "sulphur crete" material and an additional stage of flotation cleaning which could produce sulphur concentrates with purity of 98%+ having a recovery over 95%. This combined flotation process could result in a marketable sulphur product which otherwise would have to be disposed in a landfill at great expense and become a long term environmental liability.

The laboratory research of this new process is ongoing. It is hoped that enhancement of the froth flotation plant will be possible in the future to allow for processing of over 20,000 t of "sulphur crete" presently on site at the Ram River plant and other "sulphur crete" stock piles existing in landfill waste disposal sites and at other gas plants.

* * *

By using the froth flotation process not only for the sulphur base pad existing at Ram River gas plant, but also for processing the contaminated sulphur base pads existing at other sulphur gas plants in Alberta, we can contribute to the protection of the environment in the Canadian sulphur industry, which is of concern to all of us.

CONCLUSIONS

- The Ram River froth flotation process is designed to separate high purity sulphur from inorganic and organic materials such as gravel, soil, vegetation and other contaminants existing in the sulphur base pad. In this manner the sulphur base pad, a former waste product, is converted to a saleable commodity which reduces a major environmental problem in the Canadian sulphur industry and could provide revenue.

- Based on R and D studies and laboratory experiments using Ram River sulphur base pad samples, it was found that a froth flotation process, consisting of size reduction and screening to -10 mesh followed by conditioning with reagents and several stages of flotation, can provide a high sulphur purity product [typical 98.5 - 99%S with potential to increase up to 99.6%S], high recovery [98%S and higher] and tailings with a low sulphur content [10%S or less].

- Froth flotation process is characterized by a superior performance due to its higher recovery and lower sulphur content tailings, compared to hot remelting and landfill disposal, contributing greatly to reducing the environmental hazards faced by the Canadian sulphur industry.

- Further environmental protection is envisioned by processing the "sulphur crete" waste product resulting from hot remelting by a combined coarse and fine flotation process. The "sulphur crete" is currently considered unprocessable commercially and is costly to dispose of in landfills.

ACKNOWLEDGEMENTS

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Mr. G. Warne for their support in the implementation of the froth flotation technology.

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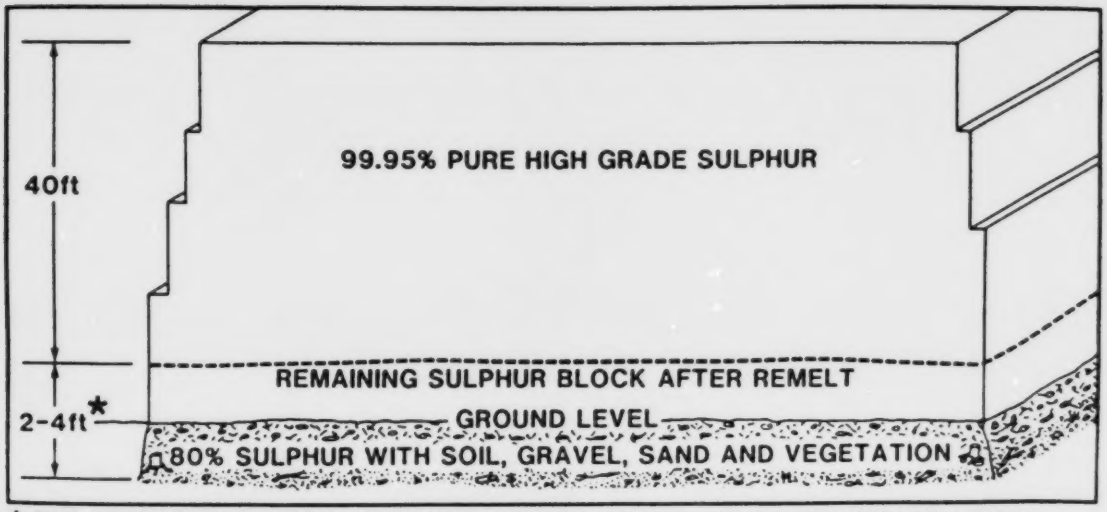
Typical Laboratory Froth Flotation Test Results for Ram River Sulphur Base Pad

PRODUCTS	WEIGHT (%)	ANALYSIS ASH (%)	ANALYSIS SULPHUR (%)	SULPHUR UNITS	SULPHUR RECOVERY (%)
FEED TO FLOTATION	100.00	18.8	81.2	81.2	100.00
FLOTATION SULPHUR CONCENTRATE	80.79	0.80	99.2	80.14	98.7
TAILINGS	19.21	94.48	5.52	1.06	1.3

Ram River Gas Plant Area Location

Husky Oil Operations Ltd. FIGURE 2

Sulphur Base Pad/Sulphur Block at Ram River



* THE RECLAIMED MATERIAL INCLUDES 1 TO 2ft ABOVE AND BELOW GROUND LEVEL

Husky Oil Operations Ltd. FIGURE 3

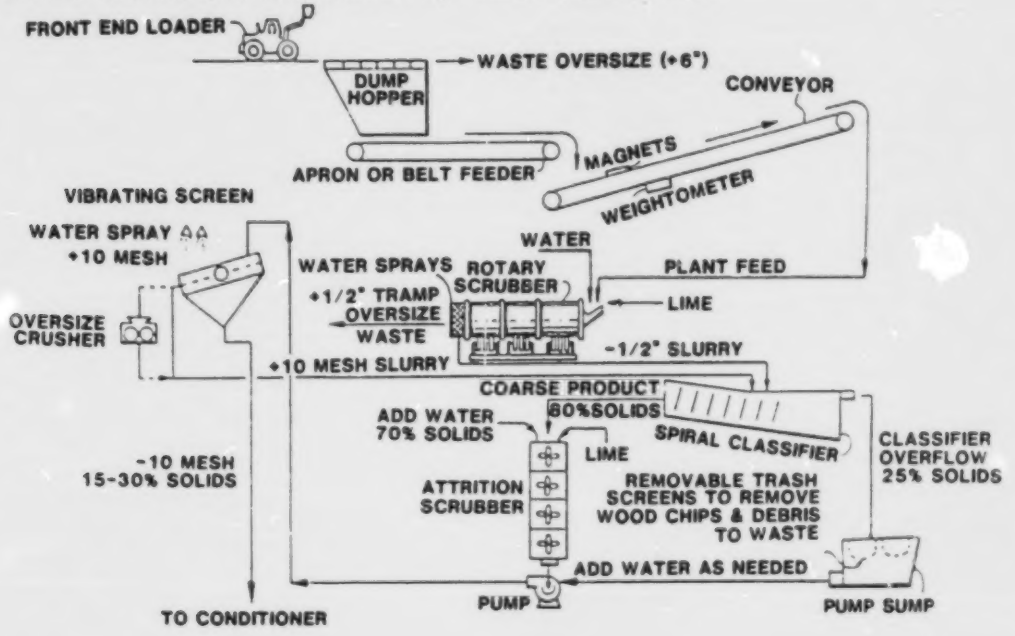
Contaminated Sulphur Base Pad Alternatives (Comparison Example)

	SULPHUR FEED (20% CONTAMINANTS)		
FEED			
QUANTITY	1000t		
SULPHUR CONTENT	800t (80%)		
CONTAMINANT CONTENT	200t (20%)		
RECOVERY	**FROTH FLOTATION (98% RECOVERY)**	**HOT REMELT (75% RECOVERY)**	**DISPOSAL (NO RECOVERY)**
SULPHUR PRODUCT			
QUANTITY (SULPHUR PURITY)	787.2t (99.6%)	602.4t (99.6%)	0
SULPHUR CONTENT	784.0t	600.0t	
CONTAMINANT CONTENT	3.2t (0.4%)	2.4t (0.4%)	
TAILINGS			
QUANTITY	212.8t	397.6t	1000t
SULPHUR CONTENT	16.0t (7.5%)	200.0t (50.3%)	800t (80%)
CONTAMINANT CONTENT	196.8t (92.5%)	197.6t (49.7%)	200t (20%)
TAILINGS DISPOSAL			
LIMESTONE REQUIRED FOR NEUTRALIZATION	48.0t	600.0t	2400t

Husky Oil Operations Ltd. FIGURE 4

Size Reduction and Classification Simplified Process Flowsheet

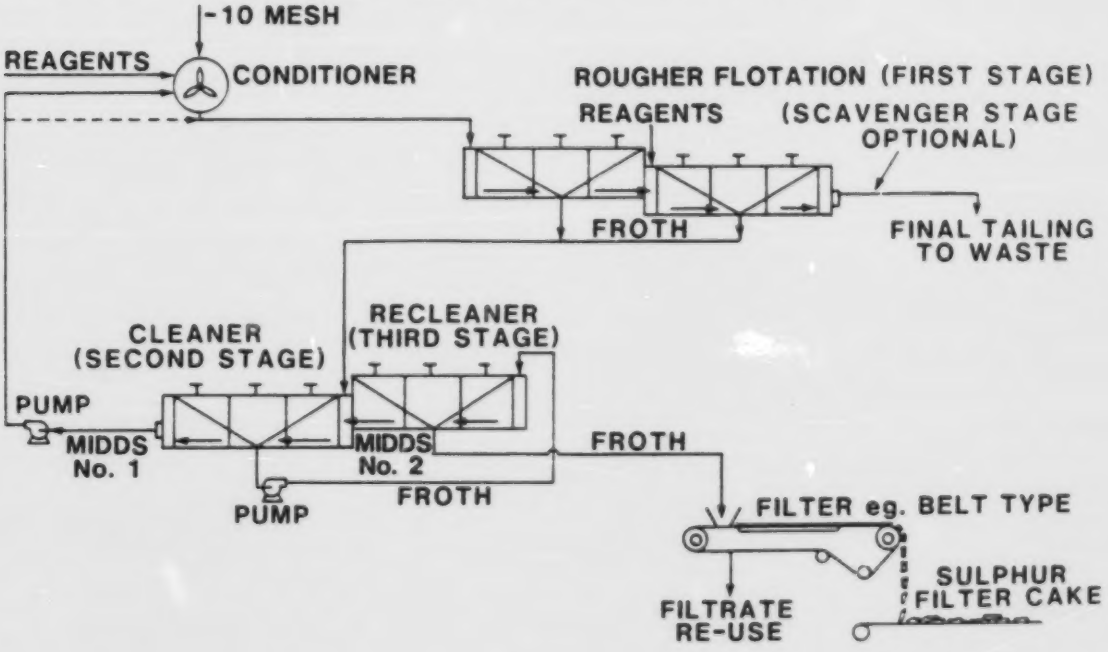
PATENTS: CANADIAN No.1223373, U.S.A. No.4871447



Husky Oil Operations Ltd. FIGURE 5

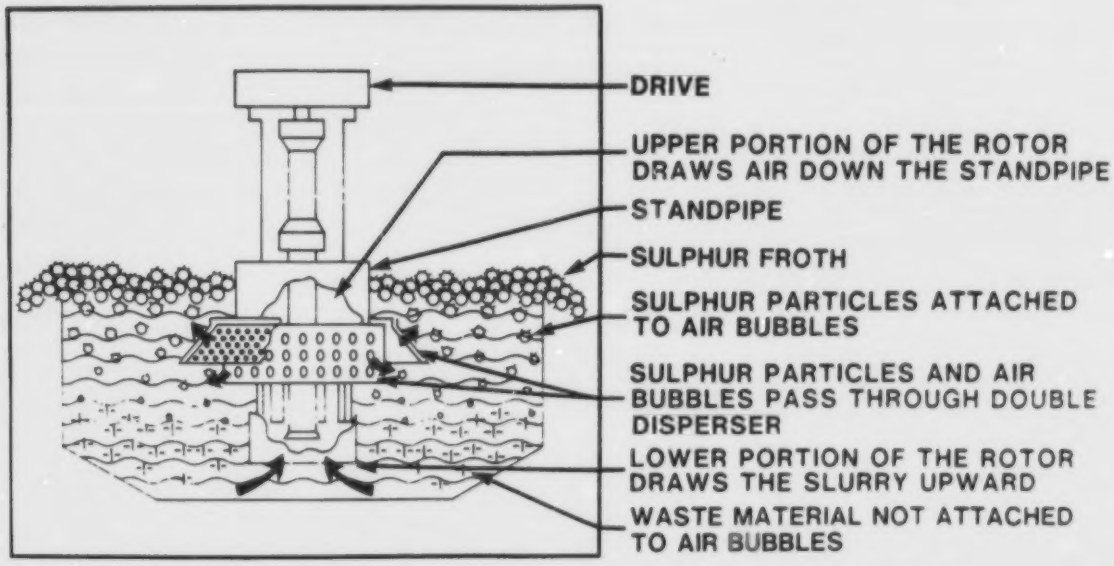
Flotation Circuits Simplified Process Flowsheet

PATENTS: CANADIAN No.1223373, U.S.A. No.4871447



Husky Oil Operations Ltd. FIGURE 6

Schematic Cross Section of a Flotation Cell


DRIVE
UPPER PORTION OF THE ROTOR DRAWS AIR DOWN THE STANDPIPE
STANDPIPE
SULPHUR FROTH
SULPHUR PARTICLES ATTACHED TO AIR BUBBLES
SULPHUR PARTICLES AND AIR BUBBLES PASS THROUGH DOUBLE DISPERSER
LOWER PORTION OF THE ROTOR DRAWS THE SLURRY UPWARD
WASTE MATERIAL NOT ATTACHED TO AIR BUBBLES

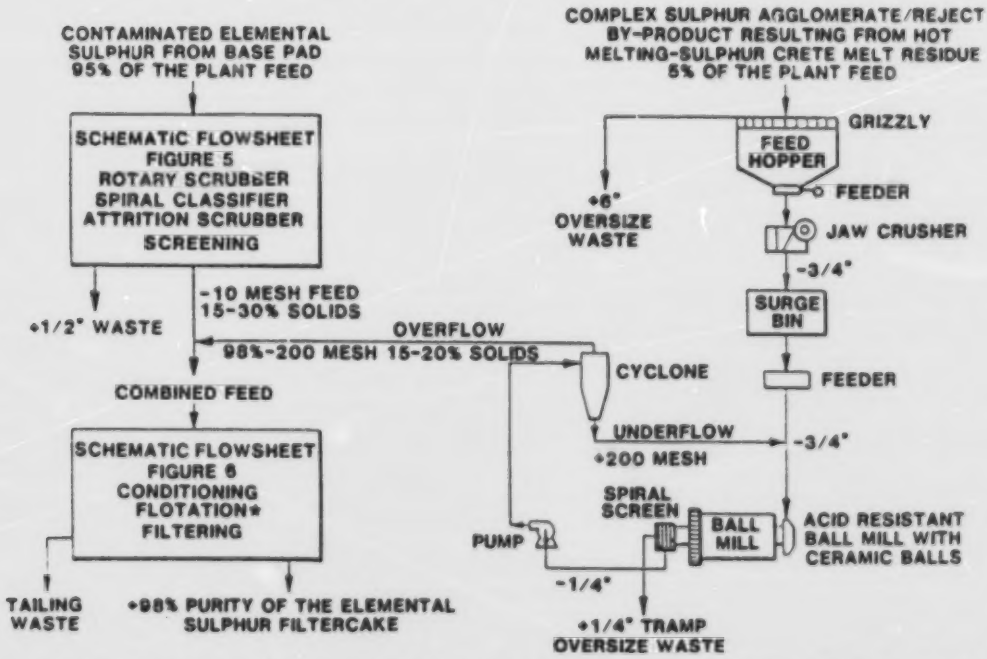
Husky Oil Operations Ltd. FIGURE 7

Combined Coarse and Fine Flotation Simplified Process Flowsheet

PATENTS: CANADIAN No.1223373, U.S.A. No.4871447

EXAMPLE FOR A COMBINED PLANT FEED WITH:

{ 5% COMPLEX SULPHUR AGGLOMERATE/REJECT BY-PRODUCT RESULTING FROM HOT MELTING-SULPHUR CRETE MELT RESIDUE +
{ 95% CONTAMINATED ELEMENTAL SULPHUR FROM BASE PAD



*THE FLOTATION WILL INCLUDE A ROUGHER FLOTATION STAGE AND THREE ADDITIONAL CLEANING STAGES.

CONTROL OF WASTE WELL CASING VENT GAS FROM A THERMALLY ENHANCED OIL RECOVERY OPERATION

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I. Introduction

The purpose of this paper is to present a case study regarding the construction and operation of a wellbore vapor recovery system. Thermally enhanced oil recovery (TEOR) operations that use steam injection in the reservoir generate return vapors. Controlling these vapors offers environmental and operational benefits.

II. Field History

The Midway-Sunset (MWSS) Field is in the southwest corner of the San Joaquin Valley, Kern County, California (Figure 1). The field extends from the town of McKittrick southeasterly along the Temblor Range foothills for over 25 miles to the town of Maricopa. The field has an average width of 3½ miles and encompasses over 50,000 acres. This field is the 2nd largest oil producing field in the State of California and is one of the largest fields, in terms of reserves, within the continental United States. Production from this field is approximately 155,000 barrels of oil per day which is produced from 9200 wells.

The arid topography varies from gently sloping alluvial fans to smoothly rounded hills, occasionally dissected by gullies (1). Surface elevations range from 500 ft. to over 1700 ft. above sea level with the productive interval occurring from just below the surface to depths below 2000 ft. The primary producing zone within the MWSS field is the Potter formation which is a heavy oil reservoir with oil gravities ranging from 9-12° API.

The first recorded oil well was drilled prior to 1890, with the first spectacular gusher recorded in 1909. This well was located near Fellows, California, and flowed in excess of 3,000 barrels of oil per day. By 1916 over 100 gushers flowing over 1000 barrels of oil per day had been placed

on production. Since this time reservoir pressures have declined. Artificial lift is required to assist the fluids to the surface.

Development of the field increased drastically around 1960 with greater demand for low gravity crude and the development and refinement of thermal recovery techniques, such as fire floods, cyclic steaming, and more recently continuous steam injection. Thermal recovery can be defined as a process in which heat is introduced intentionally into a subsurface accumulation of organic compounds for the purpose of recovering fuels through wells (2). The primary means of thermal enhancement initiated within the MWSS field in the 1960's utilized the injection of steam into wellbores. Generally, one barrel of crude oil or its equivalent is fired in a steam generator and the steam is injected into the reservoir to produce approximately 10 barrels of crude. Heat derived from the steam is used to improve the displacement and recovery efficiency of the reservoir. The major benefit of heat is to reduce crude oil viscosity due to the higher temperature which allows the oil to flow more freely into the wellbores.

Cyclic steaming and continuous steam injection are two widely used methods of steam stimulation. Cyclic steam injection consists of injecting steam into a wellbore for a period of days or weeks which is normally followed by a "soaking" period and subsequent return of the same well to production. Steam cycles are normally repeated over time. Higher fluid production is typically observed during the immediate return to production of the cyclic well. As the reservoir near the wellbore cools, production declines due to the increased viscosity of the crude oil. Cyclic well vent emissions tend to follow this same pattern.

Continuous steam injection involves the injection of steam down a dedicated injection wellbore on a continuous basis. The intent of the process is to create a steam front that moves radially away from the injector to producing wells located around it. Higher well vent emissions are associated with continuous steam injection, particularly on wells immediately offsetting the injector.

Oryx Energy Company currently operates approximately 934 thermally enhanced oil wells located on seven leases using casing vapor recovery systems (CVRS) and utilizes both cyclic and continuous steam injection techniques to enhance oil production (Figure 2).

III. Need for the System

A system to control emissions from well casings is often required to comply with environmental rules and regulations and can contribute to increased production by the lowering of near wellbore pressure. These areas are reviewed as follows:

A. Environmental

Regulation of air emissions within Kern County, California was accelerated in 1979 due to the passage of the Clean Air Act by the Federal Government. The Kern County Air Pollution Control District (KCAPCD)

passed rules as a result of this legislation that impacted air emissions and pollution control equipment within the MWSS field. Two rules resulting from this legislation led to the requirements of a CVRS: a) a "ledger system" for the emissions of air contaminants was established, and b) a rule requiring the control of casing vents of steam drive recovery wells. The "ledger system" basically consisted of keeping all emissions at a 1979 level and limiting new emissions within areas designated as non-attainment under the Clean Air Act. New emissions above the set limits were required to be offset by a corresponding decrease in old emissions and require the use of the best available control technologies. The control of steam drive well vent emissions was strongly influenced by a 1981 Environmental Protection Agency study performed on well vent emissions within Kern County, California (3). This study concluded that air emissions from cyclic wells ranged from 0.0 to 106 lbs/day/well of hydrocarbons and air emissions from steam drive wells ranged from 35 to 842 lbs/day/well of hydrocarbons. Sulfur emissions were not quantified in the Environmental Protection Agency report.

Prior to 1979 steam operated wellbores were produced with their well vents open to the atmosphere, discharging large volumes of sulfur and hydrocarbons containing gas.

Shortly after passage of these new regulations designed to control emissions from steam drive wells, Oryx Energy began permitting and installing casing vapor recovery systems on both steam drive and cyclic wells to satisfy three needs: 1) to control emissions from steam drive operations, 2) to control old emissions to offset new projects, and 3) to improve production by the lowering of near wellbore pressure.

B. Improved Reservoir Management

Historically, cyclic wellbores were produced with the well casing vents open which released large quantities of steam laden with hydrocarbons and hydrogen sulfide to the atmosphere (Figure 3). Casing vent emissions were generally visible upon the immediate return to production of cyclic wells but would diminish after the steam would condense and pressures equilibriate within the reservoir. Casing vents were generally left open in order to enhance oil production. Two alternatives were evaluated to control air emissions from TEOR wellbores. These were: 1) closing the well vent, and 2) installing a casing collection and treatment system. Closure of casing vents was determined to be an unacceptable solution for the vast majority of wellbores operated within the MWSS field. Losses in oil production could occur with the buildup of significant casing pressures associated with steaming operations if not released from the wellbore.

Fluid flow into a wellbore occurs when existing fluid (liquid and vapor) in the wellbore is removed resulting in reduced wellbore pressure. Higher pressured fluid from the reservoir surrounding the wellbore then flows into the lower pressured wellbore (4). Closing the well vent increases pressure in the wellbore to an unacceptable level and prevents oil from flowing from the reservoir into the wellbore. A vapor recovery

system for the control of well vent casing emissions was therefore advantageous to oil production because the pressure in the wellbore could be controlled.

The effect of casing vacuum on drawdown is straight-forward in that as vacuum is increased a higher pressure differential between the formation and wellbore is created thus leading to more oil production. Oil production can therefore be optimized empirically by adjusting the casing pressure or vacuum on wellbores that yields the most fluid recovery. As viscosity and differential pressure influences within wellbores are optimized so follows production. Thus the CVRS can be utilized to maintain and improve oil production.

Another benefit of the CVRS was the capturing of condensible hydrocarbons from the well casing vents. Approximately 558 barrels per day of light gravity oil (38° - 42° API) is captured, processed, and sold from the CVRS skids within the field. These hydrocarbons were previously released to the atmosphere.

IV. Major System Components and Process Flows

This section of the paper will describe the major components of the CVRS and summarize its operation. There are three primary components of the CVRS operated by Oryx Energy within the MWSS field. These are: 1) the wellhead and gathering system, 2) the CVRS condenser and compressor skid, and 3) the waste gas incinerator/scrubber system. Each are discussed as follows:

A. Overview

Currently Oryx Energy operates 28 casing vapor recovery skids located on seven leases within the MWSS field that have CVRS in place. The CVRS is an integral part of the complete lease operations. Each CVRS is composed of several individual CVRS compressor skids and gathering network piping. Typically, one waste gas incinerator is utilized for each lease to dispose of the non-condensible gases produced through each CVRS network on the lease. The average number of wells placed within a CVRS skid is 33.

B. Wellhead and Gathering System

There were two primary objectives associated with the design of the CVRS gathering network. These were: 1) the ability to handle a 10" Hg vacuum at the CVRS skid inlet continuously and a 6-10" Hg vacuum at each well casing, and 2) utilization of existing topography in order to allow fluid drainage to each CVRS skid.

The typical wellhead connection to the CVRS gathering system is illustrated in Figure 4. Threaded connections are used near the wellhead for ease of removal. Welded connections are used for the remainder of the system due to strength, longevity, and reduced fugitive emissions. Two threadolets are placed on each casing line in order to monitor pressure and temperature if needed.

In general, CVRS skids were located at the lowest point of elevation within the gathering system in order to utilize gravity drainage of the fluids. The gathering system lines utilized existing production line supports as much as possible. All main gathering lines were fabricated with a slight slope toward each skid to prevent low spots within the gathering system in order to minimize fluid accumulation within the piping. This fluid could restrict vapor flow and increase the back-pressure against the reservoir.

C. CVRS Skid

Each CVRS consists of a large air-cooled heat exchanger, compressors, liquid scrubbers, and pumps as illustrated in Figure 5. Casing vapors enter an inlet surge scrubber, V1, where free condensate is removed from the non-condensible gas stream. This vapor stream then enters the air cooled heat exchanger for preliminary condensation. Condensed fluids are separated from the non-condensible gas within a vertical scrubber, V2, prior to first stage compression. Non-condensibles then enter the interstage condenser within the air cooled heat exchanger. Additional condensed fluids are then removed within a vertical scrubber, V3, prior to second stage compression. The vapor stream passes through one last vertical separator, V4, for scrubbing prior to entering the non-condensible gas gathering system. All free and condensed fluids are pumped to a liquid collection tank, V5. The fluids are then gathered from all skids within each lease and are pumped to each respective dehydration treating facility. Typical CVRS skid design criteria is found in Figure 6.

D. Waste Product Processing

Two waste product streams are associated with the CVRS operations within the MWSS field. These have been mentioned previously and are: 1) a non-condensible gas stream, and 2) a condensible fluid stream. All non-condensibles are currently gathered from each CVRS skid within the leases and are transported at 30 psig to a waste gas incinerator for sulfur removal, treatment, and discharge. Condensed produced fluids are sent to the oil treating facilities where hydrocarbons are separated from produced water. The oil is sold with lease oil and the water is combined with other produced water and then softened at a water plant. The water then returns to the Cogeneration plant to be reheated into steam (Figure 2). Non-condensible gases are routed to the waste gas incinerator and scrubber.

E. Incinerator

The typical waste gas incinerator is comprised of two components: 1) the incinerator, and 2) a SO_2 scrubber (Figure 7). The incinerator is a cylindrical, horizontal, saddle mounted unit designed for forced draft. Non-condensible gas is regulated down to an acceptable burner pressure and is introduced into the burner of the incinerator. Burner operating temperature is normally 1625°F. This temperature is necessary in order to completely burn the hydrocarbon and hydrogen sulfide in the waste gas

stream. Pipeline utility gas must be added to the waste gas for proper combustion. If the incinerator temperature drops below 1500°F the waste gas supply is shut off. This ensures complete oxidation of the non-condensible gas.

The Incinerator scrubber contains a quench section, an integral liquid recirculation tank, a packed tower, and a mist eliminator. The scrubber is necessary in order to remove SO_2 resulting from the oxidation of H_2S within the incinerator. SO_2 removal is accomplished by saturating the exhaust gas with caustic in the scrubber quench section. The packed section consists of a stack of saddles which increases the contact area between the upward flowing gas and the downward flowing recirculated caustic. The gas passes through a mist eliminator for final particulate removal prior to exiting into the atmosphere via the stack. The CVRS accomplishes 99% removal of hydrocarbons and 95% reduction of sulfur emissions.

V. Environmental Benefits

Control of sulfur and hydrocarbon emissions are two major environmental benefits that result from operating a CVRS. Total hydrocarbon emissions controlled by the CVRS operation are estimated at 160,743 lbs/day (Figure 8). This was derived using source test data on cyclic wells and KCAPCD emissions factors for steam drive wells. In January, 1988, Oryx Energy conducted a source test of 5 CVRS skids to quantify the hydrocarbon emissions from Oryx operated cyclic wells (5). The test results showed emissions from cyclic wells averaging 98.45 lbs/day/well. Using this emission factor, total cyclic well hydrocarbon emissions for the field were 60,547 lbs/day. In order to quantify the emissions from steam drive wells the accepted KCAPCD hydrocarbon emissions factor was used (314 lbs/day/well). Total steam drive well hydrocarbon emissions for the field were 100,166 lbs/day. Steam drive wells account for only 34% of the total well count yet contribute 62% of the total estimated hydrocarbon emissions.

Hydrogen sulfide in the casing gas is oxidized in the incinerator to SO_2 and removed in the scrubber. Using a mass balance equation based upon the concentration of hydrogen sulfide in the waste gas and the quantity of waste gas, the amount of sulfur dioxide that is controlled by the CVRS can be quantified. Assuming a 95% removal efficiency, Oryx Energy controls approximately 3,558 lbs/day of SO_2 from entering the atmosphere (Figure 9).

VI. Economic Benefits

The installation of the CVRS resulted from the need to control well vent emissions for the majority of wells within the field. The approximate cost to install the CVRS fieldwide was $10,308,145.

The dynamics within heavy oil operations make it difficult to associate incremental oil production directly to the CVRS operation. Since the implementation of these systems field production has continued to increase due to many improvements within the field. It is therefore possible to assume that CVRS operations can contribute to higher oil production if used

properly. The CVRS also prevents excessive pressure buildup in the wellbore which can occur with the closure of casing well vents. Significant short term production losses have been documented when well casing pressure increases due to CVRS skid downtime. Simple payout for the CVRS can be calculated using only recovered condensate volumes. Assuming a $10.00 barrel oil price and recovery of 558 barrels of oil condensate per day project payout occurs in slightly over 5 years.

VI. Conclusion

1. CVRS plays an important role in pollution control and optimizing oil field production.

2. Successful control of hydrocarbon and sulfur emissions can be achieved with a CVRS.

3. Improved wellbore pressure control is possible with a CVRS if operated properly.

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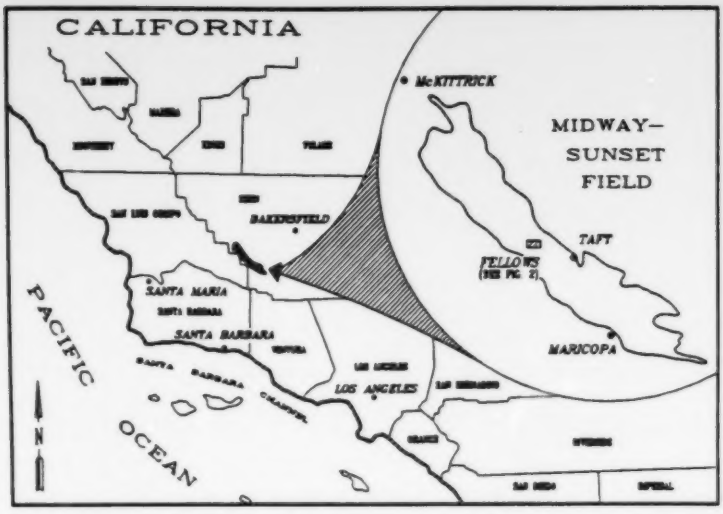

FIGURE 1. MIDWAY–SUNSET OIL FIELD LOCATION

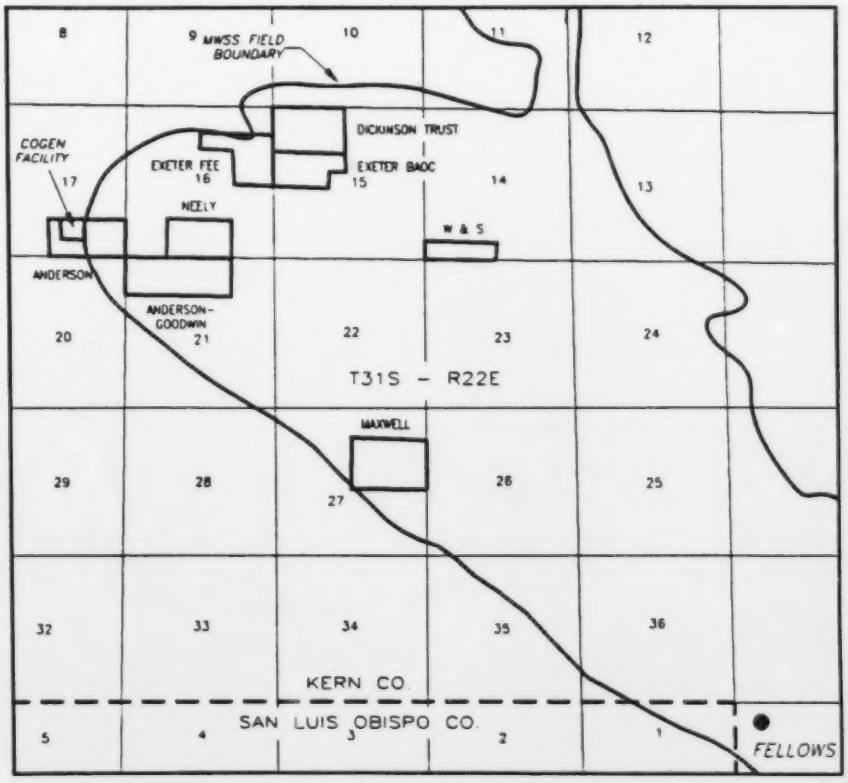

FIGURE 2. MIDWAY–SUNSET FIELD
ORYX ENERGY PROPERTIES WITH CASING VAPOR CONTROL

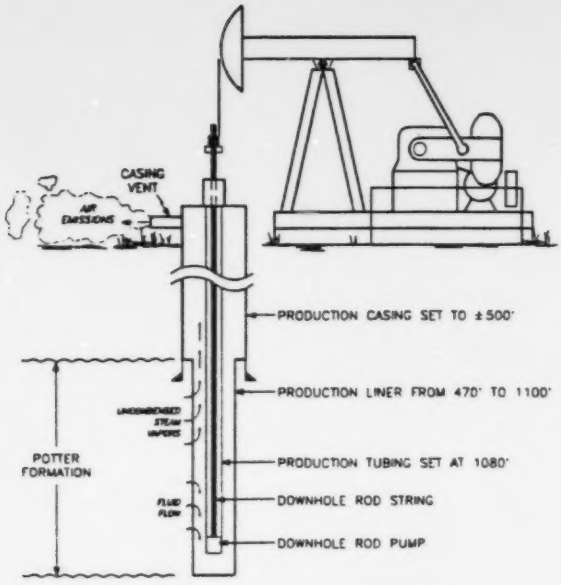

FIGURE 3. TYPICAL MIDWAY-SUNSET PRODUCER

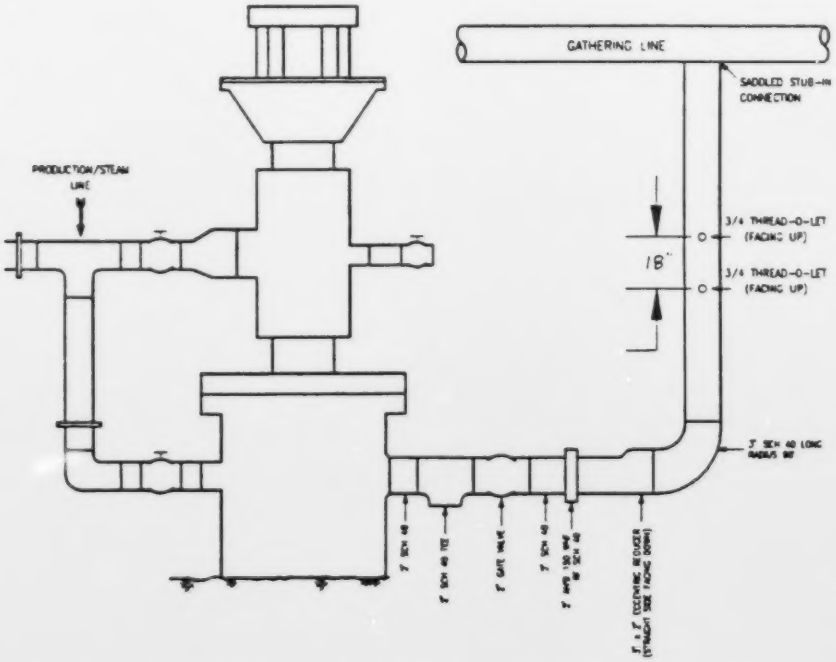

FIGURE 4. CVRS GATHERING SYSTEM WELLHEAD FLOWLINE SCHEMATIC

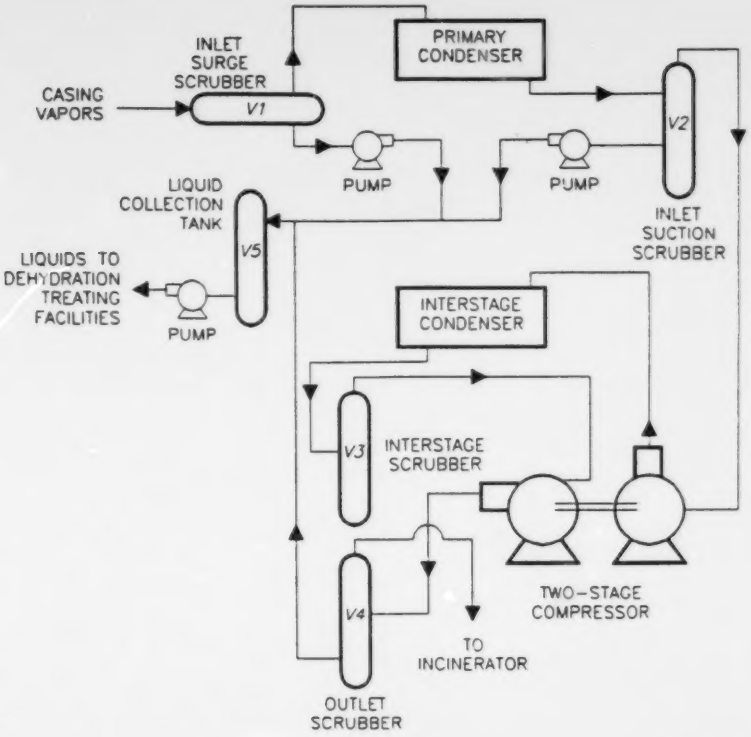

FIGURE 5. TYPICAL MIDWAY-SUNSET CVRS SKID FLOW DIAGRAM

(1) Ambient Temperature Range 20° to 115°F

(2) Atmospheric Pressure 13.86 PSIA

(3) Non-Condensible Gas 146 MSCFPD
Condensible 30 GPM

(4) Design Slug Catcher Inlet Pressure 9 PSIA
a) maximum pressure 10 PSIG (at start-up)
b) minimum pressure 8 PSIA

(5) Design Skid Discharge Pressure 35 PSIG
a) maximum pressure 50 PSIG
b) minimum pressure 30 PSIG

FIGURE 6. TYPICAL CVRS SKID DESIGN CRITERIA

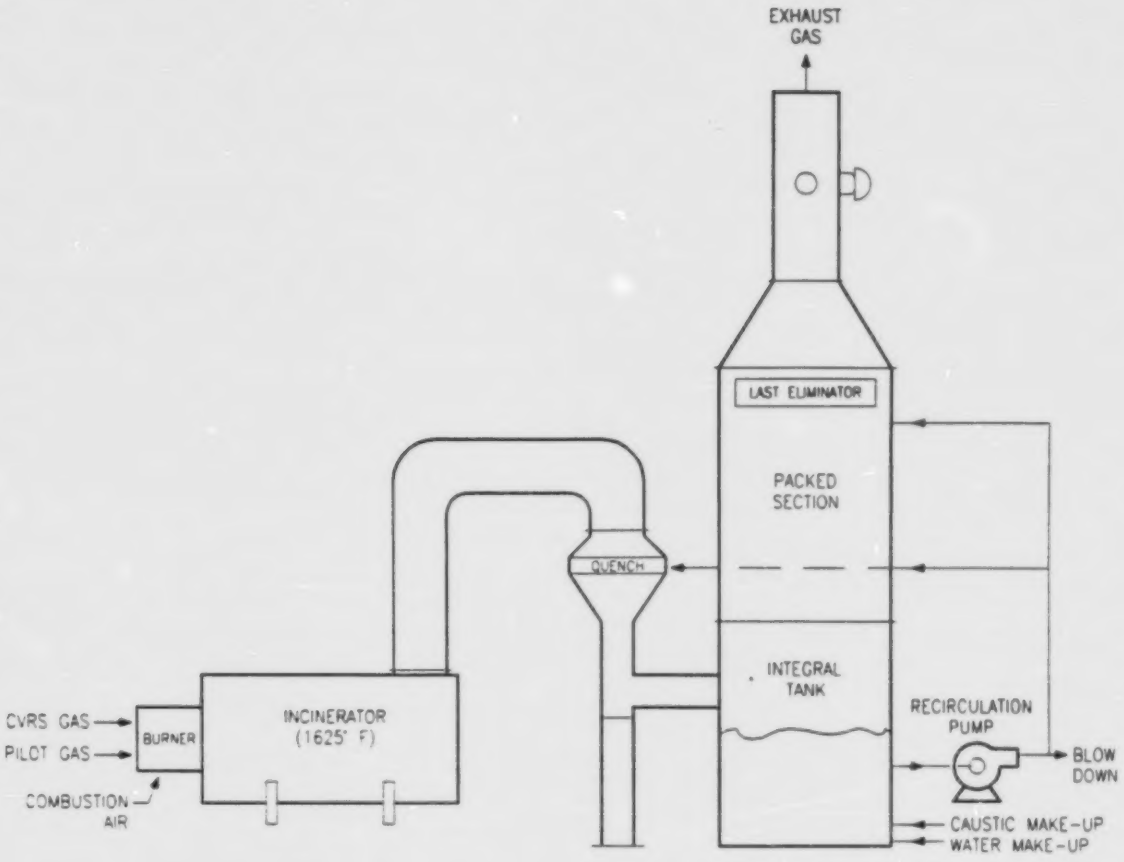

FIGURE 7. WASTE GAS INCINERATOR

LEASE	#CYCLIC WELLS	#STEAM-DRIVE WELLS	EMISSION FACTOR CYCLIC/DRIVE LB/DAY/WELL	TOTAL HC EMISSIONS CONTROLLED LBS/DAY
W & S	126	14	98 45/314	16,807
MAXWELL	93	121	98 45/314	47,154
ANDERSON/ GOODWIN	229	20	98 45/314	28,836
NEELY	167	22	98 45/314	23,358
EXETER	0	22	98 45/314	38,308
DICKINSON TRUST	0	20	98 45/314	6,280
TOTAL	615	319		160,743

FIGURE 8.
HYDROCARBON EMISSIONS CONTROLLED BY CVRS
ORYX ENERGY OPERATIONS, MIDWAY-SUNSET FIELD

LEASE	TOTAL WASTE GAS (MCFPD)	H_2S CONTENT (PPM)	SO_2 CONTROLLED (LBS/DAY)
W & S	415	4,700	313
MAXWELL	700	19,786	2,220
NEELY	315	5,730	289
ANDERSON/ GOODWIN	312	5,800	290
EXETER	340	8,195	446
TOTAL	2,082		3558

FIGURE 9.
SULFUR DIOXIDE CONTROLLED BY CVRS

THE COST OF EDUCATION

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Basic Philosophy

Education within the workplace can be a major expense, just as quality education in the private or public schools can be. The lack of quality education can be an even greater expense. Just as we can lose an educated generation to poor schools, your company can lose its profitability to a poor regulatory compliance training program. Waste management must be a major component of any industrial educational system.

There are numerous similies between the "formal" years of education and those that must follow in the workplace. Education starts with the basics in kindergarten and becomes increasingly more complex each year. This is also how education should be handled in the work force. Diversity or complexity is not divided by age or grade, but by position of responsibilty.

Remember also that education can never stop. Not only is there not a finite amount of knowledge to be taught but in the regulatory scheme of things the rules change continually, causing the need to periodically re-educate.

So much for my basic philosophy of education. I work for True Companies which is a diversified, family-owned business. Originally intended to be self supporting, we now serve the needs of the oil and gas industry. The company structure includes exploration and production, crude oil pipeline and truck transportation, crude oil marketing, a gas plant, gathering systems, drilling rigs, and a supply company. Each of these components is an individual company with its own management structure. This type of internal

structure and diversity raises many complications and challenges when creating a waste handling program. Wastes specifically exempted as "associated wastes" for exploration and production may be regulated wastes for pipeline or trucking. Wastes with minimal regulation for trucking are more cumbersome when associated with the drilling company. In a small company, because there is a lot of interaction among employees, it becomes necessary to explain the idiosycracies of regulation as well as compliance strategy when providing training.

Determination of Educational Needs

Ours is a fledgling program, so a tremendous amount of groundwork goes into the educational process. This, in my view, however is how the continuing education process should be carried out for programs that are more mature. Our training program begins by conducting a site review of key facilities for each company. Periodic informal walk throughs and discussions with supervisors keep the process fresh and compliance moving in the right direction.

During the initial site review, potential waste streams are identified. Staff interviews provide basic information as to the content and volume of these streams as well as current handling of disposal methods. As with formal compliance audits staff interviews are a critical part of this process. These interviews should be part of the continuing education of the person conducting the interview, the trainer. Arrogance or a "know-it-all" attitude on the part of the interviewer can stall a program before it gets started. The interviewer must keep an open mind and listen. Listening could eliminate the chances of asking operations to do something they've already tried but didn't work. The other great opportunity provided by listening is to hear ideas that have been building in the minds of operations personnel, ideas that could solve compliance problems. Ask the operations staff or managers if they are concerned about any particular operation. Asking supervisors questions will provide information as to the depth of their understanding of applicable regulations.

Another good source of information as to educational needs are the facility files. Review the compliance file for specific regulatory programs identified during walk throughs. Look also at previously conducted compliance audits and their action plan responses. Compliance with other enivronmental regulatory programs must be reviewed,

for as we know, many federal, state and local regulatory programs are interrelated. Overlooked compliance in one program is often an indicator of compliance problems in another program and a need for more training.

Education

Education at its most fundamental point begins with a management commitment to operate within the regulations. Upper management must communicate this commitment for the rest of the educational or training process to be successful. Without this the regulatory compliance and training personnel will run up against a brick wall from both management and operations.

As mentioned earlier, the complexity of information provided varies depending on the position of responsibility held. For example I have the luxury of meeting each manager individually to discuss items identified as problems and what is needed to correct the situation. This discussion includes the compelling regulation, why the current practice is not appropriate, the cost of changing the operation and the potential cost of not changing the operation. This discussion often includes the civil penalty structure and potential criminal penalties but not always. These discussions can get quite complex depending on the managers interest in the subject or his or her level of confusion about inequities within the regulatory structure.

Once management has "signed-off" on a program the supervisors of the affected facilites must learn about the situation. This can come down in one of two ways, an edict from management or a more casual group discussion of the problem. I prefer the more casual approach, saving the edict for resistant supervisors. The casual approach should be a give and take session discussing the problem, the regulatory program (and its intent) that facilitates the need for change and possible solutions. Give and take is important because a solution that at face value looks perfect to me may be a potential operational nightmare. Once a solution is worked out the next phase of education can begin.

To facilitate change and compliance at the operations level, a policy or procedure should be written which details, in easily understood language, exactly how a particular waste stream is to be handled. This should include a discussion of the compelling regulation, the waste to be handled,

personnel protective equipment needed, equipment required, sampling and analytical communications with environmental staff, record keeping, transportation, disposal, etc. The procedure should detail who has the responsibility for the different aspects of the program. In a small company one person can wear may hats so it is imperative that the duties for complicated waste handling situations are clearly spelled out. Not all waste handling scenarios require this level of detail. Caustic neutralization requires more detail than empty paint cans, but handling procedures must be in black and white to avoid confusion and misunderstanding.

One of the intriguing aspects of creating a waste management program for this group of related companies is cause and effect. An error in judgement on the part of trucking company could cause a waste clean up problem for the production company. Well planned coordination between the companies can significantly reduce the overall costs of compliance with waste management regulations.

A second aspect of education is the overall scope of applicable regulations. The same people from management to operations must have an appreciation for the tremendous body of regulation that governs them. They do not necessarily need to know the detail but must have a basic knowledge from which to operate and ask appropriate questions. Appropriate forums for this kind of education can be for managers at annual or bi-annual staff meetings, supervisors meetings and for operations piggy-backed onto safety meetings. Two examples of "overall scope" meetings are the interrelationships of RCRA, CERCLA, SARA, HAZCOM, and HAZWOPER or Benzene and how it is regulated under OSHA, HAZWOPER, RCRA, and CERCLA. These are complex issues but someone other than the enivronmental staff must understand how non-compliance in one program can promote non-compliance in another. The "big picture" must be known maybe not in excrutiating detail but enough that "Is it okay if ..?" is asked of the environmental staff.

An environmental compliance manual providing information about applicable regulations and company policies for the consistent implementation of these regulations is a must. This volume can be used by field supervisors for tailgate staff meetings; it should be a basic reference for engineering and planning staff. The compliance manual should be used as training modules for new or reassigned

employees. Not all employees would be required to do all modules only those which apply to their work group.

Record Keeping

While you are teaching the importance of record keeping to the operations staff, don't forget to do it yourself. Maintain detailed notes or a lesson plan of what was taught that day, include pertinent questions and answers, include a list of everyone present and the date. It is a good idea to post a synopsis of the meeting for employees who were not present and (or) as a reminder for those who were. For especially important programs it may be necessary to conduct two or three training sessions to be sure the entire affected staff is able to attend.

Remember that some regulations have specific formal training requirement such as OSHA or RCRA.

In Conclusion

Education cannot rest on its laurels. Walk through facilities periodically to remind operations of your presence. Discuss what you see with supervisors. Procedures may be in writing, you may have done training on a subject, but repeating yourself on the importance of proper waste handling can only help. Communicate, talk to people on their level, use examples they can relate to, make compliance real to your audience. Material presented over their heads will stay there and not provide any benefit. Be direct and to the point, rule number one "do not bury barrels."

Remember the rules are constantly changing. As a result you must update or change procedures and you must provide continuing education. Never take for granted that if you know something everyone does or that you told the supervisor therefore his staff knows.

One good thing about waste management and waste minimization is that you can always appeal to managements overwhelming preoccupation with the bottom line. Operations must be instructed to use products, don't waste anything, put on one more coat of paint rather than throw it away, keep inventory as small as possible, recycle used oil as fuel or in the crude oil, return used batteries. Minimize waste generation.

There are many commonsense approaches to achieving waste minimization, recyling and reduction of compliance costs. The most effective way is by education of both operations personnel and management.

DETERMINATION OF SOIL CONDITIONS THAT ADVERSELY AFFECT THE SOLUBILITY OF BARIUM IN NONHAZARDOUS OILFIELD WASTE

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Introduction

Concerns about potential changes in the solubility of barite ($BaSO_4$) found in oilfield wastes were initially voiced by Crawley et al (1). This report presented a literature review and field data on water soluble barium, plant uptake of barium, and outlined some potential environmental effects of uncontrolled land disposal of barium-containing wastes. The same report also indicated that although barium is very toxic, its geochemistry is such that it forms very insoluble barite in the presence of excess sulfate ions. The basic equilibrium chemistry of barite is such that soluble barium should not exceed 2 mg/L in a typical aquatic environment. Barium found in the barite form is also essentially nontoxic to man (even if ingested in large quantities) and severely limits barium plant uptake in the soil environment.

Literature Review

The element Ba is a divalent cation which belongs to the alkaline-earth series. Barite is the most common natural source of barium and is the primary mineral mined for barium. Due to barite's density (4.5 g/cm^3), it is commonly used as a weighting agent in drilling muds. Spent drilling cuttings are the primary component in nonhazardous oilfield waste (NOW).

Barium in soils is normally associated with the sulfate anion and has a solubility of $1x10^{-10}$. Barium is also found associated with other anions (namely carbonate, hydroxide or chloride), however these forms are far less common, probably due to their availability in the soil solution and significantly higher solubilities. At normal temperatures of 15 to 30° C these three barium salts have significantly higher ($5.1x10^{-9}$ for $BaCO_3$, and about $2x10^{-1}$ for $Ba(OH)_2 \cdot 8H_2O$ and $BaCl_2 \cdot 2H_2O$) solubilities. Therefore, in most well aerated neutral pH soils the amount of barium in the soil solution will be controlled by the solubility of barium sulfate (2).

Conditions that affect sulfate's reduction are redox and pH (2). Ultimately these conditions also control the solubility of barium. The reduction of the sulfate ($SO_4^=$) ion in the soil environment has a favorable formation constant (Log K° = 20.74), but requires very reduced conditions seldom encountered in well aerated surface soils (2). The redox potentials necessary to begin sulfate reduction in NOW is about -240 mV (pH of 8) (2). As seen in Table 1, this value requires very reduced conditions (3). Redox of this magnitude and intermittent sulfate reduction has been recorded in marshes of Southern Louisiana (4).

Although there is limited data available, recent studies on the effect of EC (5) and redox (6) on barium solubility have been performed. Sposito and Traina show barium solubility can increase slightly from 1-2 mg/L at < 5 mmhos/cm to 7 mg/L at 45 mmhos/cm with high chloride solutions (5). Deuel and Freeman show increased soluble barium with decreased redox values (6). Because of the limited nature of both studies, additional data under natural conditions may be required. In general, however, the most important factors that will control the amount of barium in the soil-pore water are:

1. **Ionic strength**, particularly the amount of chlorides as measured by EC of a saturated soil-water paste (5).

2. **Redox and pH changes**, as measured by a decrease in the Eh (electron potential) and an increase in the H^+ ion activity of the soil at or near saturation conditions (2). Eh and pH values as they relate to sulfate reduction may control the solubility of barium.

3. **Common ion effect**, as measured by the total amount of free sulfate ions from other sources such as gypsum. The presence of high levels of SO_4 ions in the soil solution can have a dramatic effect on the decreased solubility of barite.

Table 1. Jackson's Redox Potential for Given Soil Conditions (3).

Oxidation or Reduction Condition	Redox * Potential
	millivolts
$KMnO_4$ in 1 N H_2SO_4	1,500
Very well oxidized soil	800
Well oxidized soil	500
Moderately well oxidized soil	300
Poorly oxidized soil	100
Much reduced soil	-200
Extremely reduced soil	-500
$Na_2S_2O_4$ (pH 8)	-600

* Redox potential (Eh) is the most common value reported in biological and soil literature.

Study Objectives

The primary objective of this study is to determine the effects of soil-water environment on the solubility of barium found in drilling mud. Barium found in drilling muds is assumed to be almost exclusively barium sulfate. The effects of reducing conditions and high salt concentrations indicate the possible formation of other more soluble barium forms, resulting from traditional treatment and disposal practices of nonhazardous oilfield waste. A model of this treatment and disposal environment has been attempted under greenhouse conditions and monitored for one year. A simulation of this environment would allow the assessment of a long-term effect of such an environment on the solubility of barium sulfate.

Methods and Materials

Materials used in this study included both treated and untreated NOW. The treated NOW meets the treatment criteria outlined by Louisiana Statewide Order 29-B. Mainly these criteria require the reduction of electrical conductivity (EC), sodium adsorption ratio (SAR),

exchangeable sodium percentage (ESP), and oil and grease percentages. Typically these treated wastes have had a gypsum amendment. A baseline analysis of the three materials used in this study are outlined in Table 2. Materials 1 and 2 are essentially the same except for the addition of oily NOW added to increase the oil and grease concentration to about 6% (Oil and Grease Amendment). Untreated NOW was collected the day of arrival at the waste facility for the third material.

Table 2. Description of Various Treatments.

BUCKET #	AMENDMENT	TREATMENT
1	Treated	Aerated
2	Treated	Flooded
3	Treated	Aerated
4	Treated	Flooded
5	Treated Hi O & G	Aerated
6	Treated Hi O & G	Flooded
7	Treated Hi O & G	Aerated
8	Treated Hi O & G	Flooded
9	Untreated	Aerated
10	Untreated	Flooded
11	Untreated	Aerated
12	Untreated	Flooded

The three materials used in this study were placed under aerated and flooded conditions. Duplicates of materials and conditions were made for a total of twelve treatments. The description of these treatments are shown in Table 3. Figure 1 contains a sketch of the bucket design.

Table 3. Initial Readings on Samples used for Treatments.

MATERIAL	pH (s.u.)	EC mmhos/cm	Na meq/L	Ca meq/L	Mg meq/L	HC03 meq/L	Cl meq/L
Gypsum	7.3	4.85	25.9	30.0	3.8	2.3	16.7
Gyp + O&G	7.3	4.93	25.7	29.5	3.6	3.1	15.8
No Amend	7.8	25.6	233.0	35.1	4.7	2.0	232

MATERIAL	S04 meq/L	Ba mg/kg	O&G %	CEC meq/100g	Extr. NA meq/100g	Exch. NA meq/100g	SAR
Gypsum	40.4	13,640	1.03	15.8	3.09	0.50	6.3
Gyp + O&G	35.5	10,808	6.1	14.4	4.18	1.61	6.31
No Amend	31.6	8,461	1.84	21.2	32.4	9.06	52.2

Water saturated conditions were maintained in the flooded treatments by plugging the drain. Each month soil-pore water for the flooded treatments was allowed to drain out of the saturated systems, collected, and analyzed for EC and soluble constituents, including barium and zinc. Aerated treatment leachates were collected into a loosely sealed plastic gallon jug. All solutions collected were analyzed immediately for pH and EC. pH equipment was calibrated on a standard two point curve with pH 4.0 and pH 7.0 standard solutions. Electrical conductivity probes were calibrated using standard stock solutions of 720 and 20,000 µmhos/cm. Redox was measured on each of the twelve treatments with Pt electrodes standardized using a 2% $NaSO_4$ solution. Redox measurements were based on averages of several Pt electrode readings.

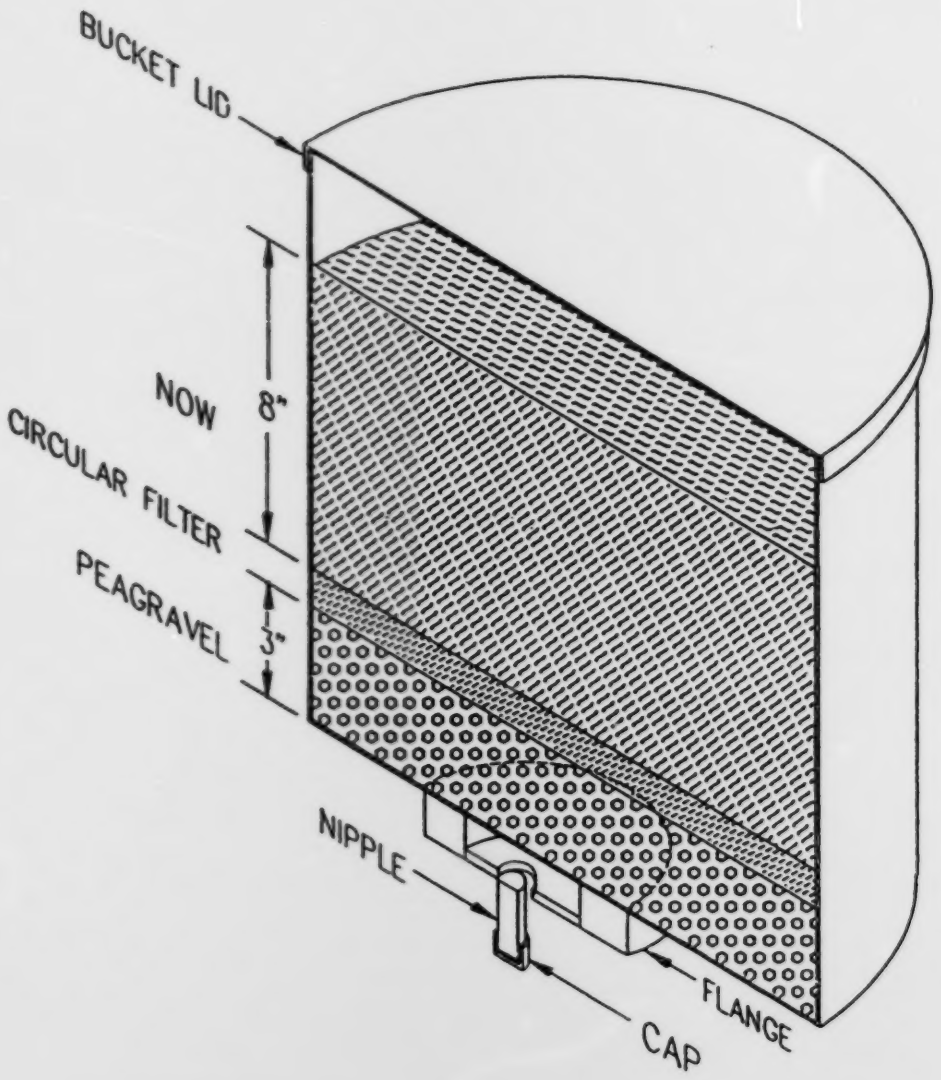

FIGURE 1: CROSS SECTION OF BUCKET USED IN GREENHOUSE STUDY

The water drained out of each system was replaced and water-logged conditions continued for another month. Because some of the flooded buckets demonstrated dispersive properties, flooded conditions were maintained with little or no loss of pore water.

Data Analysis

The following data and discussion are based on the results obtained for the period of one year. Table 4 presents a summary of the soil and water data collected every other month during the same time interval.

Redox Measurements

An initial statistical evaluation of the soil redox potential (Eh) data using the mean values of four or more platinum electrodes, collected during the last eight sampling periods indicates that these means are significantly different between the flooded and aerated treatment (1, 3, 5, 7, 9, 11, and 2, 4, 6, 8, 10, 12, respectively). The average Eh (in mV) was approximately +176, and -142 mV for the period of November 1988 to September 1989 for all of the aerated and flooded treatments, respectively. Figure 2 shows the changes in redox with time for the aerated and flooded conditions. Eh values for the aerated treatments have remained constant at approximately +180 for the past eight months. During this same eight-month period, flooded treatments have experienced a gradual decrease in redox Eh from about -11 to -240 mV, in the same period of time. The redox values for the flooded and aerated conditions are statistically different (at the 0.05 level). These were, however, the only statistical differences among the treatments due to random micro-variability of the NOW.

Figure 2. Changes in Redox in Aerated and Flooded Treatments with Time.

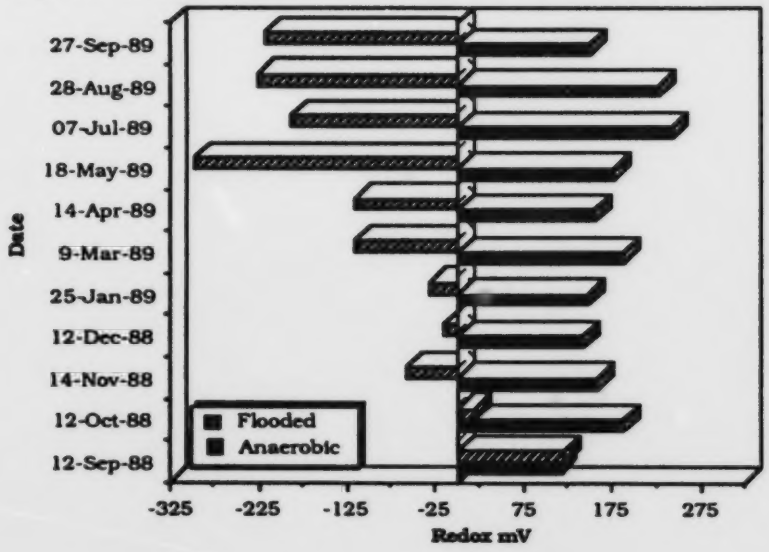

Table 4. Analysis of Chemical Parameters of Soil Pore Water Data.

Date	Bucket #	Material	Condition	pH (s.u.)	EC mmhos/cm	Na mg/L	Ca mg/L	Mg mg/L	HCO3 mg/L	Cl mg/L	SO4 mg/L	Ba mg/L	Zn mg/L
12-Sep-88	1	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Oct-88	1	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
17-Oct-88	1	Treated	Aerated	7.86	-	-	-	-	-	-	-	-	-
14-Nov-88	1	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Dec-88	1	Treated	Aerated	8.19	4.00	-	-	-	-	-	-	< 0.5	0.04
25-Jan-89	1	Treated	Aerated	7.69	4.70	595	514	47	68	732	1,720	< 0.5	0.29
9-Mar-89	1	Treated	Aerated	8.06	4.00	-	-	-	-	-	-	< 0.5	0.02
14-Apr-89	1	Treated	Aerated	8.03	3.30	542	427	38	55	615	1,440	< 0.5	0.12
18-May-89	1	Treated	Aerated	8.63	2.80	400	273	23	66	403	1,000	< 0.5	< 0.01
07-Jul-89	1	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
28-Aug-89	1	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Sep-88	2	Treated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Oct-88	2	Treated	Flooded	-	-	-	-	-	-	-	-	-	-
17-Oct-88	2	Treated	Flooded	6.94	2.28	320	314	26	256	167	1,060	0.5	0.07
14-Nov-88	2	Treated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Dec-88	2	Treated	Flooded	7.23	3.40	-	-	-	-	-	-	< 0.5	0.05
25-Jan-89	2	Treated	Flooded	7.22	2.80	265	548	46	305	111	1,700	< 0.5	0.06
9-Mar-89	2	Treated	Flooded	6.95	3.20	-	-	-	-	-	-	< 0.5	0.03
14-Apr-89	2	Treated	Flooded	6.82	4.00	-	-	-	-	-	-	-	-
18-May-89	2	Treated	Flooded	8.44	0.72	66	412	23	438	11	1,030	< 0.5	< 0.01
07-Jul-89	2	Treated	Flooded	6.91	2.40	-	-	-	-	-	-	< 0.5	< 0.01
28-Aug-89	2	Treated	Flooded	6.95	2.00	-	-	-	-	-	-	< 0.5	0.02
27-Sep-89	2	Treated	Flooded	6.92	2.20	123	324	34	80	11	744	< 0.5	0.03
12-Sep-88	3	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Oct-88	3	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
17-Oct-88	3	Treated	Aerated	7.72	-	-	-	-	-	-	-	-	-
14-Nov-88	3	Treated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Dec-88	3	Treated	Aerated	8.24	3.40	-	-	-	-	-	-	< 0.5	0.03
25-Jan-89	3	Treated	Aerated	7.64	4.10	530	504	46	27	477	1,970	< 0.5	0.04
9-Mar-89	3	Treated	Aerated	8.16	3.20	-	-	-	-	-	-	< 0.5	< 0.01
14-Apr-89	3	Treated	Aerated	7.05	2.20	284	304	23	60	300	931	< 0.5	0.28
18-May-89	3	Treated	Aerated	8.24	1.40	154	188	14	54	114	644	< 0.5	< 0.01
07-Jul-89	3	Treated	Aerated	8.22	0.88	-	-	-	-	-	-	< 0.5	< 0.01
28-Aug-89	3	Treated	Aerated	8.63	0.44	-	-	-	-	-	-	< 0.5	0.01
27-Sep-89	3	Treated	Aerated	7.85	0.80	100	106	7	82	27	298	< 0.5	0.01
12-Sep-88	4	Treated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Oct-88	4	Treated	Flooded	-	-	-	-	-	-	-	-	-	-
17-Oct-88	4	Treated	Flooded	7.10	6.42	864	642	66	1090	863	1,730	< 0.5	0.06
14-Nov-88	4	Treated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Dec-88	4	Treated	Flooded	7.28	5.50	-	-	-	-	-	-	< 0.5	0.03
25-Jan-89	4	Treated	Flooded	7.24	4.95	788	679	73	391	840	1,970	< 0.5	0.04
9-Mar-89	4	Treated	Flooded	7.03	4.80	-	-	-	-	-	-	< 0.5	0.16
14-Apr-89	4	Treated	Flooded	8.00	6.10	728	602	79	1080	479	1,960	< 0.5	< 0.01
18-May-89	4	Treated	Flooded	7.38	4.20	563	742	60	560	436	2,050	< 0.5	< 0.01
07-Jul-89	4	Treated	Flooded	7.33	4.00	-	-	-	-	-	-	< 0.5	0.03
28-Aug-89	4	Treated	Flooded	7.11	3.60	-	-	-	-	-	-	< 0.5	0.03
27-Sep-89	4	Treated	Flooded	6.9	2.80	524	489	36	323	147	1,400	< 0.5	0.03

Table 4. Analysis of Chemical Parameters of Soil Pore Water Data.

Date	Bucket #	Material	Condition	pH (s.u.)	EC mmhos/cm	Na mg/L	Ca mg/L	Mg mg/L	HCO3 mg/L	Cl mg/L	SO4 mg/L	Ba mg/L	Zn mg/L
12-Sep-88	5	Treated Hi O&G	Aerated	-	-	-	-	-	-	-	-	-	-
12-Oct-88	5	Treated Hi O&G	Aerated	-	-	-	-	-	-	-	-	-	-
17-Oct-88	5	Treated Hi O&G	Aerated	7.70	7.07	1030	772	88	333	1,370	1,650	< 0.5	0.05
14-Nov-88	5	Treated Hi O&G	Aerated	-	-	-	-	-	-	-	-	-	-
12-Dec-88	5	Treated Hi O&G	Aerated	7.65	5.00	-	-	-	-	-	-	< 0.5	0.02
25-Jan-89	5	Treated Hi O&G	Aerated	7.98	6.00	960	436	82	98	1,190	1,910	< 0.5	0.03
9-Mar-89	5	Treated Hi O&G	Aerated	7.98	4.70	-	-	-	-	-	-	< 0.5	< 0.01
14-Apr-89	5	Treated Hi O&G	Aerated	8.01	4.00	676	458	60	206	555	2,050	< 0.5	0.07
18-May-89	5	Treated Hi O&G	Aerated	7.91	3.30	453	448	41	228	359	1,560	< 0.5	< 0.01
07-Jul-89	5	Treated Hi O&G	Aerated	8.01	3.40	-	-	-	-	-	-	< 0.5	0.02
28-Aug-89	5	Treated Hi O&G	Aerated	7.93	3.00	-	-	-	-	-	-	< 0.5	< 0.01
27-Sep-89	5	Treated Hi O&G	Aerated	7.76	2.60	624	371	35	239	191	1,210	< 0.5	0.01
12-Sep-88	6	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
12-Oct-88	6	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
17-Oct-88	6	Treated Hi O&G	Flooded	7.10	8.35	1220	630	66	1190	1,470	1,810	< 0.5	0.05
14-Nov-88	6	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
12-Dec-88	6	Treated Hi O&G	Flooded	7.25	6.00	-	-	-	-	-	-	< 0.5	0.02
25-Jan-89	6	Treated Hi O&G	Flooded	7.11	5.20	879	722	80	693	1,060	1,860	< 0.5	0.07
9-Mar-89	6	Treated Hi O&G	Flooded	7.01	4.92	-	-	-	-	-	-	< 0.5	0.02
14-Apr-89	6	Treated Hi O&G	Flooded	6.93	5.40	728	815	79	1080	708	1,960	< 0.5	0.04
18-May-89	6	Treated Hi O&G	Flooded	7.28	3.90	444	557	53	701	245	1,630	< 0.5	< 0.01
07-Jul-89	6	Treated Hi O&G	Flooded	7.07	3.60	-	-	-	-	-	-	< 0.5	0.02
28-Aug-89	6	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
27-Sep-89	6	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
12-Sep-88	7	Treated Hi O&G	Aerated	-	-	-	-	-	-	-	-	-	-
12-Oct-88	7	Treated Hi O&G	Aerated	-	-	-	-	-	-	-	-	-	-
17-Oct-88	7	Treated Hi O&G	Aerated	-	-	-	-	-	-	-	-	-	-
14-Nov-88	7	Treated Hi O&G	Aerated	-	-	-	-	-	-	-	-	-	-
12-Dec-88	7	Treated Hi O&G	Aerated	7.32	5.90	-	-	-	-	-	-	< 0.5	0.03
25-Jan-89	7	Treated Hi O&G	Aerated	8.01	5.85	1028	461	81	98	1,250	2,000	< 0.5	0.02
9-Mar-89	7	Treated Hi O&G	Aerated	7.98	4.92	-	-	-	-	-	-	< 0.5	0.01
14-Apr-89	7	Treated Hi O&G	Aerated	7.64	3.60	640	379	50	252	496	1,590	< 0.5	0.03
18-May-89	7	Treated Hi O&G	Aerated	8.12	3.75	533	498	48	288	457	1,580	< 0.5	< 0.01
07-Jul-89	7	Treated Hi O&G	Aerated	7.85	3.42	-	-	-	-	-	-	< 0.5	0.01
28-Aug-89	7	Treated Hi O&G	Aerated	7.49	3.40	-	-	-	-	-	-	< 0.5	0.01
27-Sep-89	7	Treated Hi O&G	Aerated	7.71	3.20	735	473	49	312	223	1,670	< 0.5	0.03
12-Sep-88	8	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
12-Oct-88	8	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
17-Oct-88	8	Treated Hi O&G	Flooded	7.30	8.99	1270	780	90	1200	1,610	1,790	< 0.5	0.04
14-Nov-88	8	Treated Hi O&G	Flooded	-	-	-	-	-	-	-	-	-	-
12-Dec-88	8	Treated Hi O&G	Flooded	7.21	6.60	-	-	-	-	-	-	< 0.5	0.03
25-Jan-89	8	Treated Hi O&G	Flooded	7.70	5.70	1255	651	108	537	1,240	1,950	-	-
9-Mar-89	8	Treated Hi O&G	Flooded	7.21	4.40	-	-	-	-	-	-	< 0.5	0.03
14-Apr-89	8	Treated Hi O&G	Flooded	6.78	0.44	635	680	68	682	381	2,080	< 0.5	0.06
18-May-89	8	Treated Hi O&G	Flooded	7.35	4.20	501	589	67	199	272	1,750	< 0.5	< 0.01
07-Jul-89	8	Treated Hi O&G	Flooded	7.24	3.40	-	-	-	-	-	-	< 0.5	0.02
28-Aug-89	8	Treated Hi O&G	Flooded	6.96	2.90	-	-	-	-	-	-	< 0.5	0.02
28-Aug-89	8	Treated Hi O&G	Flooded	6.92	3.20	656	513	53	1350	60	1,120	< 0.5	0.02

Table 4. Analysis of Chemical Parameters of Soil Pore Water Data

Date	Bucket #	Material	Condition	pH (s.u.)	EC mmhos/cm	Na mg/L	Ca mg/L	Mg mg/L	HCO3 mg/L	Cl mg/L	SO4 mg/L	Ba mg/L	Zn mg/L
12-Sep-88	9	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Oct-88	9	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
17-Oct-88	9	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
14-Nov-88	9	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Dec-88	9	Untreated	Aerated	8.26	4.20	-	-	-	-	-	-	< 0.5	0.02
25-Jan-89	9	Untreated	Aerated	7.37	52.00	13160	2690	310	91	27,600	1,530	< 0.5	0.09
9-Mar-89	9	Untreated	Aerated	8.27	5.22	-	-	-	-	-	-	< 0.5	< 0.01
14-Apr-89	9	Untreated	Aerated	7.99	7.10	1750	228	25	77	2,920	307	< 0.5	< 0.01
18-May-89	9	Untreated	Aerated	8.19	17.00	4860	783	82	61	8,280	996	< 0.5	< 0.01
07-Jul-89	9	Untreated	Aerated	7.75	7.8	-	-	-	-	-	-	< 0.5	0.01
28-Aug-89	9	Untreated	Aerated	8.14	5.5	-	-	-	-	-	-	< 0.5	0.03
27-Sep-89	9	Untreated	Aerated	8.01	9.1	5000	297	39	91	4,480	313	0.5	0.02
12-Sep-88	10	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Oct-88	10	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
17-Oct-88	10	Untreated	Flooded	7.34	-	-	-	-	-	-	-	-	-
14-Nov-88	10	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Dec-88	10	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
25-Jan-89	10	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
9-Mar-89	10	Untreated	Flooded	7.81	9.00	-	-	-	-	-	-	-	-
14-Apr-89	10	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
18-May-89	10	Untreated	Flooded	7.95	4.80	-	-	-	1410	762	593	-	-
07-Jul-89	10	Untreated	Flooded	8.33	3.20	-	-	-	-	-	-	-	-
28-Aug-89	10	Untreated	Flooded	8.22	3.70	-	-	-	-	-	-	-	-
27-Sep-89	10	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Sep-88	11	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Oct-88	11	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
17-Oct-88	11	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
14-Nov-88	11	Untreated	Aerated	-	-	-	-	-	-	-	-	-	-
12-Dec-88	11	Untreated	Aerated	7.15	40.00	-	-	-	-	-	-	1.0	0.09
25-Jan-89	11	Untreated	Aerated	7.73	1.00	20160	2928	536	49	36,260	2,610	-	-
9-Mar-89	11	Untreated	Aerated	7.63	24.00	-	-	-	-	-	-	< 0.5	0.09
14-Apr-89	11	Untreated	Aerated	7.95	18.00	4900	477	79	150	7,450	1,550	0.9	0.04
18-May-89	11	Untreated	Aerated	8.44	7.20	1700	152	20	117	2,450	581	< 0.5	< 0.01
07-Jul-89	11	Untreated	Aerated	8.26	6.00	-	-	-	-	-	-	< 0.5	0.01
28-Aug-89	11	Untreated	Aerated	8.56	1.40	-	-	-	-	-	-	< 0.5	0.02
27-Sep-89	11	Untreated	Aerated	8.39	2.60	1000	73	5	98	692	314	< 0.5	0.02
12-Sep-88	12	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Oct-88	12	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
17-Oct-88	12	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
14-Nov-88	12	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
12-Dec-88	12	Untreated	Flooded	7.01	42.00	-	-	-	-	-	-	< 0.5	0.57
25-Jan-89	12	Untreated	Flooded	7.05	26.00	-	-	-	-	-	-	-	-
9-Mar-89	12	Untreated	Flooded	6.99	26.00	-	-	-	-	-	-	< 0.5	0.02
14-Apr-89	12	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-
18-May-89	12	Untreated	Flooded	7.25	20.00	**	**	**	187	10,510	4,340	**	**
07-Jul-89	12	Untreated	Flooded	7.94	13.00	-	-	-	-	-	-	**	**
28-Aug-89	12	Untreated	Flooded	7.68	4.00	-	-	-	-	-	-	**	**
27-Sep-89	12	Untreated	Flooded	-	-	-	-	-	-	-	-	-	-

** Insufficient Sample.

pH Measurements

While the trend is not significant, there appears to be a slight reduction in pH occurring in the flooded and treated systems (Table 4). This is consistent with the improved leaching of sodic salts, as induced by gypsum, and the increased microbial activity and increased concentration of CO_2 that occurs in flooded soil, which tends to reduce the pH. Further reductions in pH will be controlled by the rates of microbial activities and the buffering capacity of the NOW systems.

EC and Soluble Ions Measurements

The amounts of soluble ions as measured by leachate EC (mmhos/cm) for the systems are reported in Table 4. In general, the EC of untreated NOW is much higher than the treated NOW. This is expected based on the initial EC of the materials and the classic dispersal characteristics demonstrated by the untreated flooded treatments. These characteristics prevented internal drainage and concentrated EC further. The aerated untreated NOW systems also had high initial EC, but with significant leachate collections EC shows a downward trend. The EC for the eight treated buckets has decreased roughly 36 to 53% since the initial measurements.

The data on the specific ions from the water are limited at this time and will not be discussed in depth (Table 4). It should be noted that the sulfate concentrations appear to be at or above gypsum saturation in all of the 12 systems, which range from 1,500 to 2,600 mg/L SO_4. This points to the fact that both treated and untreated NOW contained sulfates. Historical analyses of NOW indicate large variances in sulfate concentrations.

Soluble Barium and Zinc Measurements

Soluble barium was measured directly from the filtered and acidified soil-pore water leachate (Table 4). These data indicate that, thus far, the soluble barium remains at or below the detection limit of 0.5 mg/L in all of the treatments. These data are consistent with the high sulfate levels detected in all of the waters from all of the buckets. Even flooded buckets, which had EC values as low as -300 mv, had <5 mg barium/L. The common ion effect is likely responsible for the undetectable amounts of barium present in the water, since excess amounts of the SO_4 ion drive the equilibrium chemistry toward the formation of $BaSO_4$.

The soluble zinc data reported in Table 4 are also consistent with the chemistry of zinc in water at above neutral pH. As expected, zinc is not very soluble in alkaline pH systems. Therefore, only traces of this element have been measured thus far in the soil-pore water of all of the systems. Zinc concentrations are expected to remain at or below these levels and even decrease further in the flooded systems due to the likely formation of very insoluble zinc-sulfides which occurs under reduced conditions.

Summary and Conclusions

The data collected from the NOW experiments indicate the following conclusions concerning flooded versus aerated systems, and the treatment effects.

- The only redox data of statistical significance was found between flooded and aerated treatments. Redox readings of the aerated treatments were not conclusive statistically between the three treatment materials. Treatment effects within the flooded and aerated conditions proved to be not significant.

- Gypsum amendments improve the physical nature of the NOW as evidenced by the lack of water movement through both the flooded and aerated unamended treatments.

- Sulfate saturated soil-pore water concentrations in all treatments indicate that both the treated and untreated NOW used in this experiment contained significant amounts of sulfates prior to the start of the experiment. The unexpected presence of high free sulfate levels in "untreated" NOW may have overridden any effect of high EC on the solubility of barite.

- The soil-pore water data indicate that both barium and zinc remained at or below detection in spite of very low soil redox values. This trend is expected to continue due to the excess SO_4 ions.

- The effect of low redox (<-250 mV) on the solubility of barite found in some of the flooded and "untreated" NOW systems may have been overridden by the unexpectedly high levels of free sulfate ions found in them. Although little evidence exists that the sulfate reduction has occurred, conditions are conducive for sulfide production as might be expected. Further research should include the effects of redox on a low sulfate system.

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THE DEVELOPMENT OF A WASTE MANAGEMENT SYSTEM FOR THE UP-STREAM, ON-SHORE OIL AND GAS INDUSTRY IN WESTERN CANADA

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ABSTRACT

This paper describes the development of a waste management system to assist personnel required to deal with wastes generated in the up-stream, on-shore oil and gas industry in Western Canada.

The system was designed to accommodate the waste streams presently generated by Mobil Oil Canada's Western Canadian operations and to serve as a guide for the treatment of waste streams which may evolve in the future. The system incorporates basic principles of waste management that are prevalent in the literature. The elements presented are:

The waste data sheet a standardized form presenting information regarding a specific waste types chemical data, possible toxic components, handling and storage methods, transportation related information, disposal guidelines, available contractor services, and regulatory and corporate contacts;

The waste tracking program a computerized data management tool for gathering information regarding: waste generating location, date that waste was generated, type of waste, volume of waste, disposal method, disposal location and contractor employed;

The site specific waste disposal manual a quick reference guide for determining safe and reliable long-term disposal options for waste materials. It provides information necessary for field personnel, working in a discreet area of a company's operations, to carry out their daily waste management needs;

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Introduction

Waste management has come to the forefront of the decision making process for the oil and gas industry in Canada. This claim is substantiated throughout the literature and is frequently a "head-line" topic for the mass media. Government ensures that companies, operating in these industries, comply with the regulations via strict, harsh penalties for infractions(1). These circumstances, as well as the acceptance of the "due diligence" process, has prompted the development of a systematic approach to the consistent, acceptable, and safe management of all waste streams.

One of the major aspects of a waste management system is the appropriate disposal of all wastes. Waste is defined as the end result of a process for which there is no further apparent use. Many of the wastes produced in the oil and gas industry are hazardous because they pose a treat to human health and the environment. This paper will outline the major components of a proposed waste disposal manual.

A waste disposal manual is intended to assist personnel required to deal with wastes generated in the up-stream, on-shore oil and gas industry in Western Canada. Research of the literature and discussions with field personnel indicate that this manual is an efficient method of organization for a large and diverse operation such as is common in the oil and gas industry. Government regulations and waste management technologies in Canada are evolving rapidly and hence the information presented in this paper is based on the best data available at this time.

The safe, long-term management of wastes requires in depth knowledge about government regulations, available waste disposal technology and the chemistry of wastes and how they react with the environment. In order to properly address all of these aspects a voluminous waste disposal manual would be required. However, in practice a voluminous waste disposal manual would not be used by field operations personnel(2). For this reason a site-specific waste disposal manual(SSWDM) has been developed.

The SSWDM system of organization addresses the unique opportunities and constraints of each identifiable area of a company's operations. Areal boundaries are determined by geographic and political region, production characteristics(e.g. oilfield vs. gas plant), and corporate managerial divisions.

Implementation of this system requires that the company follow a specific set of procedures to promote compliance with all applicable legislation and corporate environmental policy. The system will provide field personnel with information necessary to execute regular waste management tasks.

The waste disposal manual described in this paper was designed to accommodate the waste streams presently generated by Mobil Oil Canada's Western Canadian operations and to serve as a guide for the treatment of waste streams which may evolve in the future.

To ensure that the waste disposal manual is utilized and evolves along with the company's endeavors, a mechanism has been built in for modification and update. This task will rely heavily on the cooperation and assistance of field operations personnel.

Users are encouraged to participate in the modification and update process to ensure that it meets their needs and complies with all present and future waste management legislation. Ultimately this waste disposal manual should prove to be a useful tool which can be shown to be both cost effective and environmentally wise.

Background

In 1984, The Canadian Petroleum Association(CPA) published a guidance document for the petroleum industry in Western Canada(3). The primary objective of this document was to set out standards of good practices for the disposal of conventional oilfield wastes in an environmentally acceptable manner. It defines and recommends eight principles for good waste management practice in the oil and gas industry:

1. Minimize the amount of waste generated;
2. Recycle waste materials whenever possible;
3. Eliminate production of the waste whenever possible;
4. Determine the hazards associated with the waste;
5. Avoid landfill pollution;
6. Approve disposal service companies prior to their employment;
7. Use an approved hazardous waste treatment facility for disposal of hazardous wastes; and
8. Initiate research into safe disposal practices.

These guidelines were the first to propose the concept of a waste data sheet. A total of twenty waste types were provided giving limited information on waste disposal, potential hazards and regulatory requirements.

The waste data sheet was further developed in 1986 by the Petroleum Association for the Conservation of the Canadian Environment(PACE)(4). PACE developed fifty-five waste data sheets providing information on physical and chemical data, hazards, handling and storage, transportation and treatment and disposal guidelines. Many of these waste data sheets related to downstream oil and gas activities, however those associated with the up-stream were reviewed and the applicable information incorporated in the waste disposal manual.

In Canada there are many provincial and federal statutory requirements regarding the management of wastes. In 1987, the Alberta government issued the Alberta User's Guide for Waste Managers(5). This document summarizes the various acts and regulations and provides guidance for the appropriate disposal of waste material.

Two regulations relate directly to the disposal of waste in Alberta: The Hazardous Waste Regulations(Alberta) and the Transportation of Dangerous Goods Regulations(Canada).

The appropriate disposal of waste in Western Canada is primarily determined by the classification of the waste, i.e. hazardous vs non-hazardous. Most Western provinces in Canada have adopted the Transportation of Dangerous Goods Regulations as the basis for classifying wastes.

These regulations provide a list of chemicals or products which, if present, will render a waste hazardous. The Government of Alberta, through the Hazardous Waste Regulation, has provided exemption from the hazardous classification for some oilfield wastes. However, the exemption relates mainly to the manifesting and storage requirement and not to appropriate disposal. Classification of oilfield wastes in Western Canada is presently under review and as such any waste disposal manual will have to be continuously updated.

U.S. legislation and various API(American Petroleum Industry) projects were also reviewed since Canadian regulations have often followed trends in the U.S.

Discussions with operational personnel was critical to the development of this waste disposal manual. These discussions identified some of the major problems with present waste disposal practices:

a) the lack of a systematic approach, by the oil and gas industry as a whole, to waste management;

b) a vast amount of information regarding waste management regulations, technical waste disposal methods, waste chemistry and chemical protective methods dispersed throughout many documents;

c) many waste types for which there is no information available;

d) inaccurate classification of hazardous vs non-hazardous waste; and

e) the lack of a comprehensive system with which to account for waste related activities and information(types and volumes generated, disposal methods and locations used, storage and handling methods, regulatory and transportation requirements, and contractor services).

Based on this information it was determined that a "useful" waste disposal manual should:

a) provide simple, straightforward solutions to the waste management problems;

b) provide specific information relevant to their situation and locality(e.g. personnel involved in heavy oil operations do not require information concerning the handling of waste at a gas plant); and

c) provide information regarding all of the wastes that are produced in the specific area.

The elements of this waste disposal manual are the Waste Data Sheets, the Site Specific Waste Disposal Manual, the Waste Tracking Program and methods for generating, updating and modifying these elements.

Waste Data Sheets

The waste data sheet(Fig. 1) consists of eleven sections. The following is an explanation of the information provided for each section of the waste data sheet.

1. Revision Date: Each time the waste data sheet is revised this will be updated. It will give an indication of whether the data is up-to-date.

2. Sheet Number: The purpose of this number is for reference and organization.

3. Name of Waste: The most widely used name appears as the name of the waste.

3a. Synonyms: Any synonyms for the waste are to be included and identified as such. All field, chemical, and slang names must be included in order to better identify the waste data sheet to potential users.

4. Chemical Data: Based on the most authoritative literature on the chemistry of oilfield wastes.

Research of the literature was necessary to complete this section of the waste data sheet. Few oilfield wastes have had adequate chemical analysis done and therefore a waste characterization process was used to determine the chemical information. The waste characterization process is meant to assist in the identification and definition of target chemicals.

This project did not include any laboratory chemical analysis of waste.

5. **Possible Toxic Components**: The information provided was dependent upon the chemical data available in the literature.

5a. **Potential Hazards**: The synergistic effects of the chemicals that constitute the waste form the principal basis for this section.

5b. **Personal Protection**: This section of the waste data sheet contains only limited information explaining the need to address PPE. Preliminary information about Personal Protection Equipment(PPE) and information sources are provided. This section stresses the need for proper training and familiarity with handling of dangerous chemicals.

6. **Storage Methods**: Storage methods are directly related to the waste characterization process. The storage of waste is dependent upon the following characteristics: the hazards associated with the waste; the compatibility of the waste with other chemicals; the amount of waste produced on a regular basis; and the disposal options(6).

The most important characteristic used to determine storage options is the hazards associated with the waste. The storage vessel must be resistant to damage resulting in a situation that is dangerous to human health or the environment. For example, if a corrosive material is being stored then it is suggested to use non-corrosive containers. If explosive or flammable material is being stored then it is suggested to use storage vessels which are spark proof and well vented.

Details about storage options for hazardous waste are provided in Hazardous Waste Storage Guidelines, Alberta Environment, 1988(7).

All waste storage facilities must be clearly identified and - under the Federal Government of Canada's Hazardous Products Act - all workers must be informed as to the hazards posed by stored wastes through a combination of identification and worker education(8). Some wastes must be stored indefinitely, until an acceptable disposal option is discovered.

6a. **Handling Precautions**: As is the case with storage methods, the hazards associated with a waste are the most important characteristic for determining handling precautions. Precautionary measures necessary for the safe handling of hazardous chemicals are well documented(9). It was decided that the handling precautions for a mixture of hazardous chemicals are a compilation of the handling precautions for each of the hazardous chemicals in the mixture.

7. **Transportation**: The information provided is that which is necessary to complete a federal or provincial Canadian Transportation of Dangerous Goods Act (TDGA) manifest form.

This section of the waste data sheet refers directly to the (TDGA) and Transportation of Dangerous Goods Regulations (TDGR). Hazardous substances, including wastes, are regulated under this act and must be manifested when transported (7). The main reasons for this practice are: to ensure that hazardous materials are comprehensively managed; to indicate to first responders the hazards present in the event of a transportation accident; to aid in the determination of packaging and other precautionary measures necessary for safe transportation; to assist in the tracking of dangerous goods; and to delineate potential routes of travel (7).

The degree of hazard posed by a substance determines its TDGA classification. If it falls below the well defined limits set out in the act then it is not considered hazardous, under the act.

It was found that the petroleum wastes examined are often difficult to classify under the TDGA due to their diverse constituency. In these cases the waste mixture was classified as the most hazardous chemical present in the waste and comprising the largest component of the waste. However, all chemicals in the waste were considered to ensure that low concentrations of extremely hazardous chemicals were addressed.

Wastes that were determined, through the literature, to be sufficiently hazardous to warrant classification under TDGA which were not explicitly regulated (i.e. the name of the waste did not appear in the list of regulated substances in the act) were classified as Not Otherwise Specified (N.O.S.). This classification scheme is legislated under the TDGA and is based on the hazardous nature of the waste.

In situations where neither of the above methods were possible with the available information, it is indicated on the sheet that the waste is not listed in the TDGA and therefore a chemical analysis of the waste is necessary to determine its hazards and subsequent TDGA classification.

7a. TDGR Identification Number: The product identification number (PIN) corresponding to the regulated name of the waste is provided.

7b. TDGR Classification:The hazard classification number corresponding to the regulated name of the waste is provided. These numbers are in the Alberta User Guide for Waste Managers (1987). Either a waste was classified as a substance appearing in the TDGA, in which case the classification number was given, or a waste was classified due to the identified chemical hazard.

There are seven potential characteristics which may, depending on the magnitude, cause a substance to be considered hazardous under the TDGA. These characteristics are: explosivity, corrosivity, reactivity, radioactivity, flammability, toxicity and inclusion on a Federal or Provincial dangerous substance list (10).

7c. Type of Carrier: This refers to the vehicle required to transport the waste under the TDGA.

7d. Waybills Required: A waybill is a document describing goods shipped by rail or truck. For wastes regulated under the TDGA a federal manifest is required. Company specific manifest requirements are also indicated.

7e. Loading-Unloading Precautions: The activities reviewed include loading, unloading, transferring, transporting and packaging of the waste. The information that provided was based on the safe work procedures outlined in Glenn and Sterling (1988)(9) and Glenn et al. (1988)(10).

8. Disposal Guidelines: A designation of either "Hazardous" or "Non-hazardous" for each waste type under this section of the waste data sheet is provided. This designation is not the same as the hazard classification system used in the TDGA. The reason for this is that the Disposal and Transportation sections of the waste data sheet provide information for different purposes.

For example, under TDGA a solid substance is considered to be biologically hazardous (toxic or poisonous) only if the LD-50 (oral, rat) is less than 200 mg/kg (11). However, there is potential for adverse health effects to occur from prolonged exposure to a substance with a much higher LD-50 rating. Therefore the potential for workers or the environment to be exposed to chronic (long-term, low-level) toxic levels of harmful substances is strong and must be considered.

Determination that a waste was hazardous under the Disposal Guidelines section of the waste data sheet was based on the following considerations:

a) the waste or a chemical in the waste was classified as hazardous under the TDGA;

b) the persistent toxic substances: (PTS) polycyclic aromatic hydrocarbons or heavy metals (which are commonly found in oilfield wastes) were in the waste; or

c) information from the literature suggesting that the degradation products from a waste disposal technique contained PTS's. (e.g. heavy metal contaminated fly ash from an incinerator used to incinerate waste oilfield sludge).

For those wastes for which it was impossible to obtain information from the literature regarding hazard potential, it is indicated on the waste data sheet that it is necessary to determine the hazards prior to the identification of potential disposal options.

The waste disposal options that are provided on the waste data sheets include various combinations of the following techniques: chemical treatment, physical treatment, biological treatment, thermal treatment, storage (long and short term), recycle, reuse, recovery, reduction, minimization, transformation, engineered redesign, and substitution (12).

The potential disposal options presented on the waste data sheets are based on the following classification scheme:

Ideal: The ideal disposal option is either the only available option, the best available option, or the most practical option available. The ideal disposal option must meet the following two criteria:

1- it is in compliance with all existing laws; and

2- it is not harmful to human health or the environment.

Acceptable: An Acceptable disposal option is substandard to the Ideal disposal option. Either cost, efficiency, logistics, or feasibility make it less desirable than the Ideal disposal option. However, it meets both criteria necessary to be an Ideal disposal option and therefore may be employed if necessary.

Alternatives: Alternative disposal options are those with an unproven track record. Either due to a lack of case study, a lack of scientific study, or a strong potential for undue risk the disposal option is not implementable. The alternatives section is a compendium of all potential disposal options which may in the future through research and development attain Acceptable status or ultimately replace the Ideal option on the waste data sheet. However, Alternative disposal options do not meet the Ideal option criteria and should never be employed in the field.

9. Contractor Services Available: Listed contractors that offer waste management assistance to the petroleum industry were identified through review of the Alberta Special Waste Services Association (ASWSA) Directory, 1988. Each of the waste data sheets has at least one potential contractor service listed. Selected contractors should be approved through a corporate purchasing program.

10. Regulatory Agency Contacts: List of provincial and federal agency contacts are provided

11. Environmental And Regulatory Affairs Contacts: A contact from the Corporate Environmental Department is provided.

Site Specific Waste Disposal Manual(SSWDM)

The site specific waste disposal manual is intended to address the wastes and concerns specific to an area of a company's operations. This can be organized depending on the business aspects of a company but more often on the type of oil and gas activities being conducted in a part of the organization.

An inventory of all waste types generated in the area must first be compiled. This will require close communication with operating personnel since often an accurate inventory is not kept. Also, operating personnel may be well acquainted with local contractors and disposal facilities. A review of provincial regulations must be conducted. In some cases the facility or area is covered under two separate legislative jurisdictions.

Once all the information has been gathered the site-specific waste disposal manual can be organized as follows:

1. Waste Identification;
2. Present Waste Management Methods;
3. Waste Data Sheets; and
4. Instructions for Using the SSWDM.

The resulting manual is often a small pocket size book with twenty or less waste data sheets which can easily be referenced by field personnel.

Waste Tracking Program

A waste tracking program was developed to keep track of waste types, volumes, and disposal method and location. The program is PC based and can be used by all field personnel. Waste information is gathered either through truck tickets or purchase orders and is submitted to head office on a monthly basis. Each site-specific waste disposal manual has instructions on the use of the program.

Discussion

One of the major problems in developing a waste disposal manual is in obtaining accurate characterization of a waste product. This often requires in-depth discussions with field personnel, chemical manufacturers and extensive laboratory analysis. Mixtures such as sludges and filter backwash material are often difficult to characterize. Also filters, primarily from gas plants, are of particular concern.

Furthermore, treatment techniques, prior to disposal, are still being tested for many waste products.

The development of waste data sheets is an important component of a waste management program. The sheets provide generic information regarding each specific waste type. They contain information collected about a waste including waste disposal techniques which are innovative and unproven. Additional research will be necessary to address PPE on a site-specific basis once a chemical analysis has been done to determine the hazards of various wastes.

While investigating the waste management practices used in Mobil Oil Canada's field operations it was discovered that field personnel often had suggestions for how to manage wastes. Some of these suggestions were truly insightful and upon further investigation were deemed to be non-harmful to human health or the environment and in compliance with government regulations and company policy.

An example of this is the draining of used oil filters through a homemade screening device. It was made from an old drum fitted with a strong metal mesh about six inches from the bottom. This practice facilitates the recycling of used lubricating oil. Suggestions such as this should be incorporated into the waste data sheets.

Information regarding waste data sheet modification must flow from field to head office and vice versa via the waste data sheet modification process. However, waste data sheet updates should be disseminated from head office out to all applicable operating areas. This convention will help to ensure: that waste data sheet control remains central to the corporation; that new information is acceptable prior to implementation; and that all areas of the company's operations will reap the benefits of additional information.

Waste data sheet updates should be sent out each time a waste data sheet is modified. Each area in possession of the respective waste data sheet must be notified of the changes. The person responsible for management of the area should be instructed to replace the old waste data sheet with the new version and destroy the old version.

The current status of a waste data sheet is determined by the Revision Date appearing in the top left hand corner of each waste data sheet. A master copy of the Waste Data Sheets must be kept on file located in head office and will serve to verify the current status for each waste data sheet.

Field generated information regarding actual waste management practices is to be recorded using the waste tracking program.

The function of the waste tracking program is to provide a mechanism to record all waste related information. This information is necessary for SSWDM development, waste data sheet creation, and to protect the corporation's interests. Field personnel should be responsible for recording information about waste disposal. It was discovered that field personnel have a reluctance towards recording waste related information. They perceive it as a task which makes their work more complex and, by slowing them down, appears to make them less productive. However, due to the attention recently given to hazardous waste by the media, field personnel are beginning to realize the importance of using company approved waste management practice including the tracking of waste related information.

Decisions regarding waste management require a knowledge of chemistry, safety, toxicology, governmental regulations and the regulatory process, and waste disposal technology. Personnel making these decisions should be trained to deal with waste management issues and to identify and reduce the associated risks.

Since the SSWDM is a sub-set of the waste management system, changes to the SSWDM must be done by qualified personnel and controlled from a location central to the corporation. The rationale for this is that decisions regarding waste management have potential to produce catastrophic results.

The waste data sheets provide a comprehensive list of all waste types generated by the company and a mechanism to address them. This is a very important consideration for oil and gas companies that are now forced to exercise due diligence in all waste related activities. A company operating in the oil and gas industry can use the waste data sheets to effectively manage their wastes.

The waste disposal manual will assist the company in the identification and correction of any waste management practice which may cause adverse effects on human health or the environment. The manual provides a window into the company's operations regarding waste and how it is handled. Most importantly, it provides a mechanism to monitor waste management practice for compliance with existing laws.

This waste disposal manual presents the opportunity for companies, operating in the oil and gas industry, to approach the management of their wastes in a systematic manner. In doing so they will help to ensure compliance with all waste related legislation thus reducing the risk associated with waste handling, transportation and disposal. The manual provides the company's field personnel with a document which is focused, easily understandable and comprehensive.

It enables environmental professionals to summarize waste related data and present upper management with meaningful information regarding waste management problems.

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REVISION DATE: SHEET NUMBER:
NAME OF WASTE: (Synonyms:)
CHEMICAL DATA:
POSSIBLE TOXIC COMPONENTS: Potential Hazards: Personal Protection:
STORAGE METHODS: Handling Precautions:
TRANSPORTATION: TDGR Identification Number (PIN): TDGR Classification: Type of Carrier: Waybills Required: Loading & Unloading Precautions:
DISPOSAL GUIDELINES: (Hazard Classification) Ideal: Acceptable: Alternatives:
Contractor Services Available:
Regulatory Agency Contacts:
ENVIRONMENTAL AND REGULATORY AFFAIRS: Contact Waste Management Coordinator at: (XXX) XXX-XXXX

Fig. 1 Waste Data Sheet

THE DEVELOPMENT OF AN OBM CUTTING CLEANER IN THE NETHERLANDS

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Introduction

Drilling with oil based muds[OBM] can result in a considerable reduction of drilling time and costs(1), compared with water based muds[WBM]. However, the big disadvantage of OBM is the discharge of oil contaminated cuttings and the impact on the marine environment(2).

On offshore drilling locations in the Netherlands, discharge of oil contaminated cuttings into the sea is allowed provided the average oil content[OC] is below 100 grammes of 1000 grammes of dry cuttings per section of the well being drilled with OBM. Monitoring around drilling locations, where in the past oil contaminated cuttings[OCC] have been discharged, showed a longterm negative effect on the marine environment(3).

In order to minimize the above-mentioned effect the Dutch authorities are stimulating clean technology to be developed to cope with the problem of OCC. In 1987 the Dutch government decided to support financially a project for the development of an OBM cutting cleaner, having the following objectives:

- to reduce the OC on OCC below 20 grammes per 1000 grammes of dry cuttings;
- to recover the base oil in such a condition that the oil can be re-used;
- to process 3 to 6 tonnes per hour and the unit should be applicable offshore;

- the discharge of the dried OCC[DOCC], after treatment by the process should not introduce an extra environmental hazard for disposal on- or offshore.

Onshore the Netherlands OCC, having more than 50 grammes of aliphatic oil by dry weight are considered to be a chemical waste, which has to be treated before disposal.

This paper comprises results of a longterm onshore fieldtest with the new development of an OBM cutting cleaner, which has processed 1200 tonnes of OCC.

OPERATING PRINCIPLE

The operating principle of the OBM cutting cleaner is as follows[see figure 1]:

From the collecting tank[1] the wet oil contaminated cuttings[WOCC] are pumped with a hydraulic pump into the feed screwconveyor[2] of the rotating assembly[3]. The shaft with hammers of the rotating assembly is driven by a diesel engine[4]. The outside of the rotating assembly wall is heated with thermal oil from the thermal oilheater[5]. When entering the rotating assembly, the WOCC are crushed and heated simultaneously. By crushing the cuttings a large area for heat transfer is created and any water and oil within the cuttings are released.
The solids are discharged via the discharged screwconveyor[6] at the bottom, while the steam/oil mixture is discharged via the upper outlet into a cyclone[7].
Any dust taken along with the steam/oil mixture is separated in the cyclone, while the vapor is cooled with an aircooler[8] and collected in a sludge tank[9]. In this tank three phases, water, sludge and clean oil, can be distinguished.

RESULTS OF THE CAPACITY-PERFORMANCE TESTS

In order to determine the average capacity of the OBM cutting cleaner several bottle-necks had to be overcome. The major problem during the startup period was to realize a continuous feed into the rotating assembly.

Another problem was the large amount of large stones or other litter present in the WOCC, which often caused the plugging of the feedsystem and excesive wear of the hammers. Due to a too low velocity of the steam/oil vapour mixture in the horizontal section of the pipe from the rotating assembly to the cyclone, solids could settle. This resulted also in plugging of the horizontal pipe. After modification of the unit which resulted in solving the above-mentioned problems the reliability increased up to 85% and the amount of manpower to operate the unit went down from 3 to 2 men per 12 hours shift.

The capacity of the unit has been calculated from thermodynamic properties, which are dependable on the oil- and watercontent of the WOCC. Official capacity testruns, held during the field trial and supervised by an independent consultant, revealed the following capacity-performance of the OBM cutting cleaner, as shown in table 1.

TABLE 1
Comparison between actual and calculated capacity

Testurns	Oil* %	Water* %	capacity tonnes/hour calculated	actual
no. 1	9.1	7.5	2.0	2.14
no. 2	12.3	11.0	1.7	1.14
no. 3	13.0	13.0	1.5	1.5
no. 4	11.7	18.9	1.2	1.1

* content of oil or water by dry weight in WOCC.

The average capacity during the processing of the whole batch of 1200 tonnes was calculated to be 1.3 tonnes per hour. Oil-, water-content and hammer-wear are parameters which can have a great influence on the capacity-performance of the OBM cutting cleaner. These influences have been established and based on the studies carried during the pilot testing, proposals for modifications are being evaluated in order to increase the capacity of the unit. With these modifications, new calculations show that it is possible to achieve a capacity of 3 tonnes per hour.

RESULTS OF THE ENVIRONMENTAL-PERFORMANCE TESTS

In 1986 the Dutch authorities instructed the national working group on clean technology[WST] to study alternative technology to treat OCC. After studying several alternatives the OBM cutting cleaner has been selected to have a good potential for a solution for the problem of oil contaminated cuttings.

The working group WST developed a model to assess the environmental performance of these technologies, which has been named the "black box"-approach. The basic philosophy of this approach is to screen environmentally the discharges and recovered products resulting from the application of these technologies, to get information whether these discharges can disposed on- and offshore and also, to assess if the recovered products can be re-used without having an extra environmental burden.

Based on the "black box"-approach the following environmental performance parameters have been considered to be applicable when testing the OBM cutting cleaner:

a. the determination of the massbalance for the solids, water and oil in order to evaluate the capacity of the process;

b. to determine the influence of certain processparameters, like energy requirement, the residence time of the cuttings, the process temperature and pressure;

c. to analyse the physical-chemical characteristics of the wet - and dried(treated) oil contaminated cuttings e.g.:
   - oil - and water content;
   - the content of polycyclic aromatics, heavy metals and salts;
   - leach out tests in rainy - and seawater for the assessment of the disposal on - and offshore;
   - the particle size distribution for the evaluation of the spreading mechanism into the marine environment;

d. to analyse the physical-chemical characteristics of the recovered base oil e.g.:
   - the determination of the density, flashpoint, the kinematic viscosity and the boiling range in order

to compare the recovered oil with the original base oil;
- GC/MS-fingerprinting for comparison with the original base oil;
- the content on polycyclic aromatics and heavy metals for the assessment of the influence of the process-parameters, like temperature and pressure, on the quality of the recovered oil;

e. to determine the drilling fluid properties of an oil based mud made with the recovered base oil by:
   - determination of the rheological properties according to API RP 13B;
   - density, oil/water-ratio, HPHT, etc. according to API RP 13B;
   - simulation tests for down hole emulsion stability of the mud;

f. to test the oil based mud made with the recovered oil for the marine aquatic toxicity towards three marine organisms(one algae and two crustacea);

g. to test the dried(treated) oil contaminated cuttings for the marine sediment toxicity towards a marine sediment reworking organism.

Due to the limited space available for this paper only the most important results will be presented here.

During the fieldtrial two different OBM-cuttings have been processed, namely cuttings contaminated with OBM nr. A and cuttings contaminated with OBM nr. B, having different base oils as make-up oil in their mudformulations. The complete analysis as prescribed in the "black box"-approach has been carried out by an independent laboratory. Before each official testrun sampling strategies have been discussed and agreed upon in order to garantee a representative sampling. Table 2 presents an overview of the oilcontent on cuttings before and after processing by the OBM cutting cleaner during testruns 1 and 2. Field measurements are results obtained by applying the retortprocedure as prescribed by the Dutch regulations, while the laboratory applied a Dutch standard procedure. As can be noticed a small difference have been experienced between the two procedures.

TABLE 2
Results of the oilcontent on cuttings

Sample	Testrun 1 % oil by dry weight		Testrun 2 % oil by dry weight	
	Labresult	Field	Labresult	Field
WOCC(feed)	9.1	9.5	12.3	12.7
DOCC(treated)	1.0	1.2	1.1	1.3

The conclusion of the independent consult and laboratory is that the OBM cutting cleaner can reduce the oilcontent on cuttings to approximately 1% by dry weight.

The results of the petrochemical analysis for the recovered oil from OBM nr. B is presented in table 3, where also the comparison of properties is shown with the original base oil Shell Sol DMA.

Table 3
Petrochemical properties of the recovered oil compared with the original base oil

Property	Standard	Unit	Testrun 2 Shell Sol DMA Original	Recovered
Flashpoint	ASTM D93	°C	98	98
Density (15°C)	ASTM D1298	kg/l	0.7978	0.8003
Viscosity (40°C)	ASTM D445	cst	1.99	2.05
Boiling range	ASTM D86	°C	223-269.5	223-275

The GC/MS fingerprinting confirms that the recovered oil is very similar in quality as the original base oil Shell Sol DMA. In the case of the recovered oil from OBM nr. A, which is formulated with BP 83 HF, the same results have been experienced.

During the fieldtrial temperature-changes in the process of less than 10 degrees C did not have any effect on the quality of the recovered oils. This have been verified by GC/MS-fingerprinting of the recovered oils.

Table 4 presents the concentrations of aromatic hydrocarbons, the polycyclic aromatics(PAHs) and the heavy metals analysed in the oil, recovered during testrun 2.

Table 4
Aromatics, PAHs and heavy metals in recovered oil

Parameter	Unit	Concentration
Heavy metals:		
Cadmium	mg/kg	< 0.1
Chromium	,,	1
Copper	,,	< 1
Mercury	,,	< 0.1*
Nickel	,,	< 1
Lead	,,	< 1
Zinc	,,	< 1
Arsenic	,,	< 0.2
Total aromatics	wt %	0.11(0.03)**
PAH's(16 of EPA)	mg/kg	4***

* mercury measured in aqua regia-destruate
** average result of a three-fold measurement. The concentration in the original Shell Sol DMA has been determined to be 0.03 wt%
*** only naphtalene has been detected.

Based on the results as presented in table 4 the following conclusions can be drawn:
- in the recovered oil the concentration of aromatic hydrocarbons is found to be slightly higher than the original base oil Shell Sol DMA. Regarding the presence of PAH's, only naphtalene has been detected;
- no heavy metals have been encountered in the recovered base oil.

No explanation has been found why the recovered oil contains a slightly more aromatic hydrocarbons and naphtalene than the original base oil. Therefore it was decided to check the emulsifiers, applied in the OBM nr. B for the presence of PAH's. Analysis shows that no PAH's could be detected in the emulsifiers.

Also a GPC-analysis(gelpermeationchromatography) has been carried out in order to determine the content of emulsifiers in the recovered oil. The conclusion is that due to the small concentrations of these emulsifiers applied in the OBM-formulations, no emulsifiers could be detected.

Disposal characteristics of the OCC before and after treatment

The disposal characteristics of the OCC are determined by the chemical composition, the particle size and the leaching properties when the material has to be dumped onshore or into the marine environment.

The WOCC as well as the DOCC have been analysed for nine heavy metals: cadmium, copper, chromium, mercury, nickel, lead,zinc, arsenic and barium. Besides that also the PAH's have been analysed in the WOCC.
From the results it is concluded that basically none of the heavy metals, except for barium, surpass the reference concentrations as set by the Dutch government for disposal onshore and into the marine environment. Onshore the WOCC is considered to be a chemical waste, based on the barium - and oilcontent, while the DOCC is a chemical waste, based only on the bariumcontent. Also the saltcontent will cause a problem onshore, that's why the waste material has to be disposed onshore on special dump locations. No PAH's have been detected in the WOCC.

The particle size-distribution(2-2000 um) was determined in the WOCC and the DOCC. The results show that although more of the smaller particles are expected to be present in the DOCC than in the WOCC, this appears to be not the case for particles of smaller than 63 um. The explanation for this result is that this could be a consequence of the analysis due to the treatment of the WOCC prior to the measurements. Such a experience has also been reported in the literature(1). From the physical appearance of the DOCC, which is a powder, it is concluded that the spreading in the sea will be enhanced compared to the sticky material, like the WOCC. Computer modeling of the spreading mechanism of these materials into the sea has confirmed this expectation.

For the determination of the leaching properties of the waste material the WOCC and the DOCC have been subjected to two cascade tests; in one case acidified demi-water (pH at the beginning of the test= 4) has been used as a leaching medium, and in the other case artificial seawater was used. The tests have been carried out in accordance with the Dutch standard procedure NVN 2508. The leaching liquids have been analysed for:

- 11 heavy metals: cadmium, chromium, copper, nickel, lead, zinc, mercury, arsenic, antimony, barium and molybdenum;
- chloride;
- oil.

The results of the cascade tests on the WOCC and the DOCC indicate that the most components, except for barium, chromium, molybdenum and oil, are leached out in only limited amounts. Oil and molybdenum are more easily leached out of the DOCC than out of the WOCC. For barium and chromium, no difference in leaching behaviour from both waste material has been noticed. The concentrations of the heavy metals, which are leached out in artificial seawater, are below the target-levels as set by the Dutch government for seawater, except for barium which leach-out concentration surpasses the background level in the seawater.

Mudproperties of drilling fluids made with the recovered base oil

In order to show if the recovered base oil can also be re-used as make-up oil for oil based muds, tests to determine the mudproperties have been carried out according to the standard procedure for field testing drilling fluids, API RP 13B 11th ed.(1985), on such a mud. The mud made with the recovered base oil has also been subjected to hot rolling during 16 hours at 120 degrees C under the following downhole simulation conditions:

- without any influx;
- with a 10%(w) seawater influx;
- with an influx of 86 grammes per liter $MgCl_2.6H_2O$-water-solution.

These tests have been carried by a Dutch mudsupplier and an oilcompany. After interpretation of the results the main conclusion is that the recovered oil can be re-used to formulate adequate oil based drilling fluids.

The toxicological behaviour of a drilling fluid based on the recovered base oil and the treated DOCC

A drilling fluid, based on the recovered oil and having the same mudformulation as OBM nr. B, has been prepared for aquatic toxicity testing according to the Dutch regulations by a government appointed independent laboratory. The toxicity of aqueous extracts of the OBM was determined for three organisms:
a. the crustacean chaetogammarus marinus
b. the brown shrimp (crangon crangon)
c. the marine algea skeletonema costatum.

The results of the aquatic toxicity-tests have been compared with those of the original OBM nr. B and found to behave similar. When these results are evaluated by applying the relative cut-off-values as set by the Dutch authorities the OBM nr. B, based on the recovered oil, is approved.

A sediment toxicity test with treated DOCC using the sediment reworking organism, the heart urchin Echinocardium cordatum, has been carried out during a test period of 14 days. Although the test method is still under development, it is concluded that the DOCC may be harmful for the heart urchin at 0.32 grammes per kilogrammes dry sand and higher concentrations. Compared with results of the sediment toxicity tests of the OBM nr. B, the DOCC seems to be more toxic. A possible explanation may be the better leaching behaviour of the oilcomponent from the DOCC compared with the WOCC, contaminated with OBM nr. B. The Dutch government intend to start a new project to study meso-cosm experiments on the long-term behaviour of the DOCC on sedimentary ecosystems gathered from the Dutch North Sea continental shelf.

CONCLUSIONS

After processing 1200 tonnes of OBM cuttings an OBM cutting cleaner has been developed with an average capacity of 1.3 tonnes per hour of wet oil contaminated cuttings[WOCC] and achieving a reduction of oil on cuttings to approximately 1% by dry weight. From the petrochemical analysis and the GC/MS-fingerprints it is concluded that the recovered oil is similar to the original base oil.

Oil based muds made with the recovered oil show to have the same stable emulsion - and rheological properties as the original mud. The toxicity results of the mud made with the recovered base oil has passed the criteria set by the Dutch authorities. Onshore the DOCC has to be disposed on special dumpsites, while for the disposal offshore more research is needed in order to assess the impact on the marine environment. However it is expected that the longterm impact of the DOCC is less compared to the discharges of the WOCC due to better spreading mechanism and leaching characteristics.

Although the objective to process 3 to 6 tonnes per hour has not yet been achieved, the unit can be improved. After modifications, based on a thermodynamic and mechanical evaluation of the results obtained during the pilot plant tests, an offshore unit with the capacity to handle the amount of cuttings being generated while drilling a 12 1/4"-hole with OBM is viable within one year.

ACKNOWLEDGEMENTS

This project has been supported by the company Solids Control Services, the Dutch organization of gas & oil producers(N.O.G.E.P.A.), the oilcompanies N.A.M. and Conoco Netherlands Oil Co. and the Dutch government.

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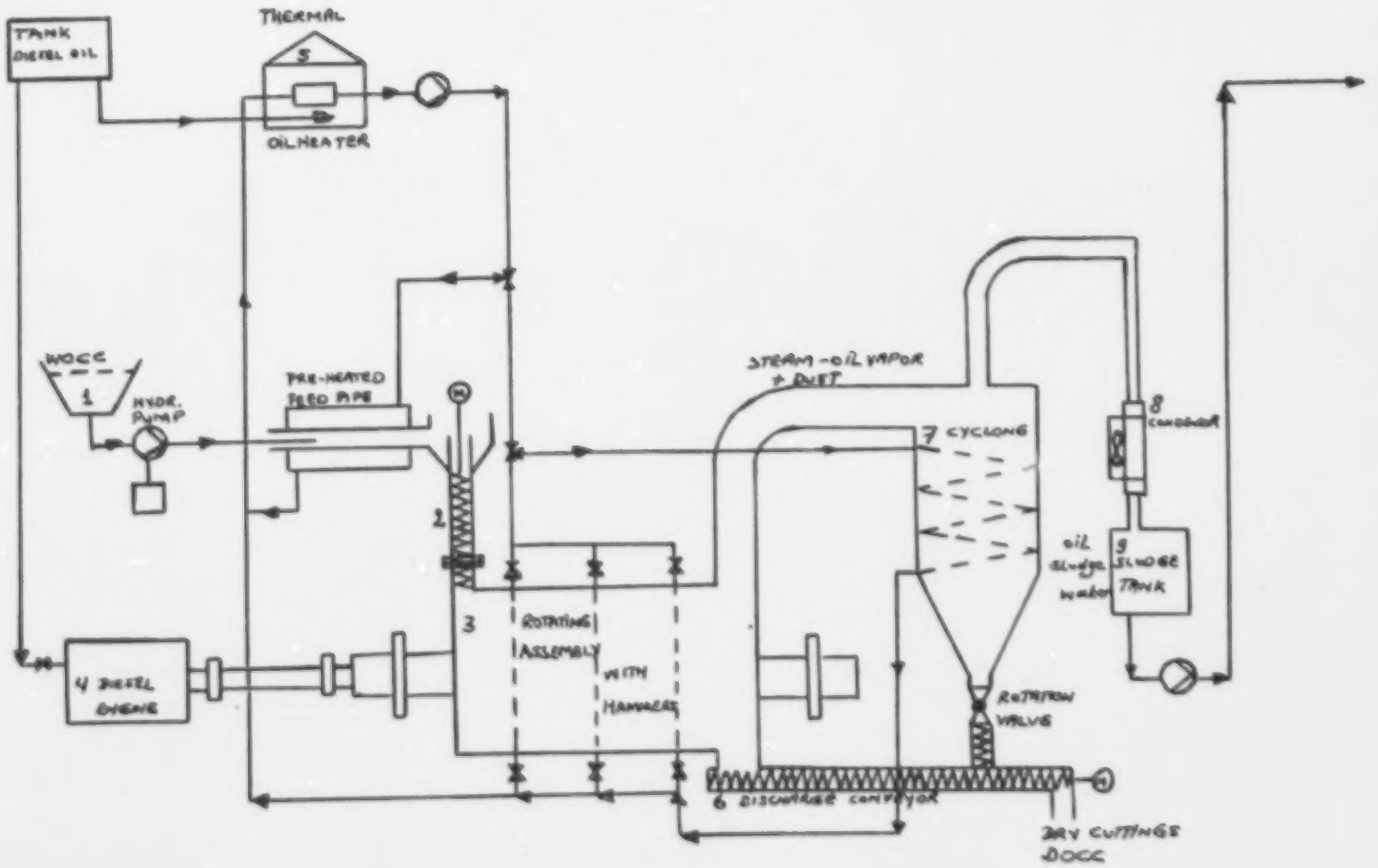
TANK
DIESEL OIL
THERMAL
5
OIL HEATER
HOCC
1
HYDR. PUMP
PRE-HEATED FEED PIPE
2
3
ROTATING ASSEMBLY WITH HAMMERS
4 DIESEL ENGINE
STEAM - OIL VAPOR + DUST
7 CYCLONE
8 CONDENSER
9 SLUDGE TANK
oil
sludge
water
ROTATION VALVE
6 DISCHARGE CONVEYOR
DRY CUTTINGS DOCK

FIGURE 1.

DISPOSAL PRACTICES FOR WASTE WATERS FROM COALBED METHANE EXTRACTION IN THE BLACK WARRIOR BASIN, ALABAMA

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INTRODUCTION

An emerging industry has developed in Central Alabama's Black Warrior Basin to recover a natural resource that until 1980 was considered by the mining industry to be a dangerous waste by-product. An industry that can neither be defined strictly as an oil and gas production operation or as a mining operation, coalbed methane extraction has expanded into the 1990s with exponential growth. It has been estimated by the U.S. Bureau of Mines and the National Petroleum Council that coal seams may contain in place gas reserves of 398 trillion cubic feet (TCF)(1). The Black Warrior Basin, alone, is estimated to contain in place reserves of 19.8 TCF(2), with recoverable reserves approximately 16.0(3). The first Alabama coalbed methane well was permitted in 1980 and by January 1, 1990, the industry had permitted 2,068 wells.

Of primary environmental concern to the fledgling industry is disposal of water produced in association with the methane. The produced water ranges from 'fresh' to 'brackish', but does not approach the definition of brine associated with that produced by conventional oil and gas operations. The water quality is identical to that from coal seams in the minable depths (less than 1,500 feet) and increases in salinity with depth. Currently primary disposal methods of produced water are: (1) National Pollutant Discharge Elimination System (NPDES) permitted stream discharge and (2) land application by Industrial Land Application Treatment Permit.

Management of disposal of produced water and non-point source discharges, normally associated with construction, is essential to prevent water quality degradation. This paper will present a case study of the evolution of the coalbed methane extraction industry in the Black Warrior Basin of Alabama and one company's approach to protection of the environment through waste management and responsible environmental planning.

BACKGROUND

As the energy needs of the United States continue to increase and the availability of conventional domestic resources continue to decline, unconventional fuel sources that provide environmentally clean and economic energy must be exploited. Coalbed gas meets these criteria and also reduces the necessary required safety emissions of methane by mining operations.

Coalbed gas is present in all coalbeds to some extent. Concentrations of methane usually ranges between 80 - 99%. When these concentrations are mixed with air to form a mixture of 5 - 15% methane a highly explosive vapor is formed. This may be easily ignited by any spark

caused by mining operations. In 1969, Congress recognized the inherent dangers of coalbed gas and legislated the Federal Coal Mine Health and Safety Act which issued limits for methane concentrations in mines. To assure compliance with these standards and for safety aspects, mining operations included the venting of coalbed methane gas to the atmosphere with no capture of these resources. It is noted, however, that the capture and use of these gases was studied in 1953 by the Council of the Organization for European Economic Cooperation(4) and even in the early 1900's a minor scale project in the Powder River Basin produced gas from a water well that heated ranch buildings(1).

In 1980, the National Petroleum Council concluded that "natural gas from coal seams, Devonian shale, and tight gas reservoirs could make significant contributions to the United States gas supply"(5). The United States Department of Energy sponsored additional study and further defined the coalbed methane resource potential of the major coal basins of the United States. In addition, the Gas Research Institute (GRI) published geologic assessment reports on the natural gas reserves in various United States coal basins. To date, the major basins that are being developed for coalbed methane production are the San Juan Basin in Southern Colorado and Northern New Mexico and the Black Warrior Basin found in West Central Alabama.

In Alabama, coalbed methane production now contributes approximately 12% of the annual gas production. The increased activity in drilling presently occurring in the outlying frontier areas of existing production will soon exceed this production value(6). An intense program is underway to drill as many wells as possible by January 1, 1991, which will qualify a large amount of production for the special tax credit for unconventional fuel sources under the amended Section 29 of the Crude Oil Windfall Profits Tax Act of 1980. The production produced from these wells will continue to earn the tax credit (presently $0.86 per MCF) until the year 2000.

Coalbed methane gas is found in two forms in the coalbeds: (1) free gas found in the fractures and fissures of the coal, and (2) bound gas which is adsorbed to the coal particles. The adsorbed gas accounts up to 95% of the methane and desorbs with comparatively slow rates over an extended period of time. The amount of gas contained in a particular coalbed seam in a particular basin depends on many factors including : (1) depth of overburden, (2) hydrostatic pressure, (3) geological conditions, and (4) coal rank. In the Black Warrior Basin, there are specific stratigraphical horizons comprised of multiple coal seams that range in thickness from two to eight feet. These are known as the Pratt, Cobb, Mary Lee/Blue Creek, and Black Creek Zones. Gas contents of these coal seams range from 200 to 550 standard cubic feet/ton of coal(6).

To allow the production of the gas, adsorbed to the coal particles, it is necessary to create a pressure drawdown which requires the removal of the water that naturally occurs in the coalbed fractures and fissures. This water results from migration of surface waters downward until it is trapped by the coal seams or from water which was present at the time of deposition and stratification of the coal beds. As the water is removed, by pumping, the gas is desorbed from the coal, and flows into the wellbore. The gas and water flows up the tubing-casing annulus and tubing, respectively.

ENVIRONMENTAL CONCERN

The disposal of the produced water is both a major environmental and economic concern. Water production rates vary from basin to basin, from coal zone to coal zone, from seam to seam

within the zone, and even varies to the geographical area within a given coalbed methane field. Rates upward to 1,000 barrels per day have been reported in the Black Warrior Basin. Just as rates vary, so does the chemical composition with variations from depth to depth and area to area. The major contaminant of concern found in the produced water is chloride. However, various trace elements such as iron and manganese are also found in the produced water.

Additional environmental concerns resulting from coalbed methane extraction operations include non-point source discharges which result primarily from run off and erosion of newly constructed roads, pipelines, and drilling locations and the multiple land use (mining, silviculture, agriculture and residential) in and adjacent to the area of operations.

In 1987, Amoco Production Company, after achieving successful results in the San Juan Basin, began an intensive effort to develop the coal gas reserves in the Black Warrior Basin. This project involved Amoco alone and in partnership with Taurus Exploration, Inc. The area of operations cover approximately 160,000 acres located between Tuscaloosa and Birmingham, Alabama, along the Black Warrior River (Fig. 1). The majority of the land is forested and could be considered semi-wilderness. The many streams in the area are tributaries of The Black Warrior River, a controlled level river that is used for transportation and electric power generation in addition to recreation (skiing, swimming, boating, and fishing). Early in planning, Amoco recognized the potential impact on the environment by its operations and endorsed a position of cooperation with the regulatory agencies controlling coalbed methane operations, the Oil and Gas Board of Alabama (O&GA) and the Alabama Department of Environmental Management (ADEM). A goal of maintaining the environment in as near to pre-existing conditions as possible, with the providing of improvements where possible, while developing the natural resource (methane gas) was adopted.

Amoco approached the commingling of the capture of a natural resource with protection of the environment by commissioning studies by The University of Alabama, Auburn University, and a major environmental consulting firm. Studies identified potential effects on aquatic species by NPDES discharges and general groundwater information, plant and soil effects by land applied produced water and an overall view of environmental aspects of the total project. The University of Alabama studies, although limited in time and scope, confirmed areas of work previously performed(7) (8) in the aquatics field and added to the base of information for toxicity to indigenous species. With the aid of the Geological Survey of Alabama, an initial groundwater assessment study for Tuscaloosa, Jefferson, and portions of Walker Counties, Alabama was done. The studies performed by Auburn University provided initial studies upon produced water disposal through land application and the effects on soil structure and plant life, along with a brief review of potential use of produced water in aquaculture. An environmental consulting firm reviewed the overall environmental aspects of the project, including air, noise, aesthetics, archaeological, wetland determination, land use and other areas of potential concern.

This paper will focus on issues pertaining to water quality maintenance and overall environmental planning.

WATER DISPOSAL

STREAM DISCHARGE

Stream discharge of produced waters is permitted by NPDES Permit issued by the ADEM , under primacy from the EPA, which prescribes effluent limitations for chlorides, iron, manganese and pH. Although coalbed produced water is not technically classified as brine (>3.5% dissolved solids), they are slightly to moderately saline. Chloride concentrations range from 150 mg/l to 11,000 mg/l. Iron concentrations range from <0.05 mg/l to 0.2 mg/l(7), and pH ranges from 7.3 to 9.0. There may be other detectable associated inorganic constituents that vary with area but are not limited under NPDES permitting.

In 1982, studies were undertaken by the ADEM and Alabama Methane Production Company in association with Dames and Moore to set effluent limitations for stream discharge of produced waters. Initial NPDES discharge guidelines were restricted to 500 mg/l total dissolved solids (TDS) instream. The EPA ultimately moved from "technology based" permitting to toxicity based requirements and cited numerous investigations on aquatic species toxicity to chlorides(8). The EPA, in establishing an instream chloride limit, selected data based on acute and chronic toxicities for two (2) species of vertebrae (fathead minnow and rainbow trout) and one (1) invertebrae (ceriodaphnia). The acute values ranged from 1470 mg/l to 6570 mg/l. The final acute value adopted was 1720 mg/l. A conservative standard was established at 50% of the adopted acute value (860 mg/l) as the criterion maximum concentration. (A maximum value not to be exceeded for more than one hour every three years, i.e. an acute value). The final acute-to-chronic ratio for the three species was 7.6. To establish a value to protect the aquatic species over their life history, the acute value (1720 mg/l) was divided by the ratio thus a value of 230 mg/l, i.e. a chronic value. This value is a four day average that cannot be exceeded more than once every three years(9). The ADEM, furthermore, established a 7 day average once every 10 years low flow as a basis for the NPDES Permit, which resulted in a more conservative number.

In June 1989, the GRI and the Geological Survey of Alabama (GSA) jointly issued a 5-year study of effects of produced water chlorides on aquatic species. This study concluded that the 230 mg/l limit as established by the EPA "is sufficient to protect warm water species occurring in relatively natural streams"(7) and "a threshold value of 565 mg/l was determined below which no significant change of macro invertebrate community was observed"(7).

Due to potential for variation of produced water and the interaction with insitu stream waters, The University of Alabama, Department of Mineral Engineering and Department of Biology, was commissioned to study the effects of produced water on-site of the Amoco project area. The study was conducted during the Summer of 1989 with results confirming those of the GRI/GSA. Effects on total macro-invertebrate taxa and taxonomic richness from The University of Alabama study are shown in Figures 2 and 3, respectively. Corresponding chloride concentrations for effluent and instream are found in Figures 4 and 5. As the instream chloride concentration at Shoal Creek increased, a decrease of total macro invertebrate taxa was seen. However, this was not experienced at the Fox Creek Test Site. It is apparent that the decrease in total taxa was not completely dependent upon chloride concentration, but may have been influenced by instream components and subsequent mixtures. At neither site was taxonomic richness (total species) affected by chloride instream concentrations.

Acute toxicity testing yielded results similar to those of the GRI/GSA long term studies(10). However, an area identified by The University of Alabama as a potential major concern was the

interaction of low dissolved oxygen content and high chloride concentration with the effect on species. Although no direct correlation was identified, it appeared that this interaction may have resulted in data that was inconsistent. This interaction may possibly be a source identified by O'Neil, et al(7) to have also yielded inconsistencies during toxicity testing.

Stream discharge is accomplished by collection of produced water from individual wells to a central treatment facility. This facility normally consists of two ponds, each with a 10,000 barrel capacity that are lined with a one-piece polyethylene liner. The ponds are designed to allow for aeration in the receiving pond and also provide retention time to allow for flocculation and settlement of iron and manganese. The flow continues into the second pond by gravity flow. The volume discharged is metered. The discharge occurs through a diffuser placed parallel and upstream to the stream flow. Wet chemistry monitoring and analysis is performed weekly on criteria required by the NPDES Permit and at more frequent intervals as is dictated by stream conditions.

LAND APPLICATION

Land Application of all types of waste waters has been used throughout the country with various results. In Land Application a specific form of the effluent, either partially treated or untreated, is released at specified times onto designated land area. Some waste supply nutrients to the covering vegetation. However, chlorides provide no nutrient value and may cause an upset to the osmotic balance and result in a growth decrease or death of the vegetation. Additionally, application of water over an extended period of time to a specific area may result in loss of vegetation due to oxygen reduction. Also, chlorides may alter the soil chemistry resulting in an unstable soil that is unable to support vegetation.

Since very little information on land application of coalbed produced water was available, Auburn University was commissioned to study the effects resulting from land application(11). The study consisted of three (3) phases: (1) on-site investigation of sites under short term application and long term application, (2) greenhouse studies of plant effects by produced water application, and (3) soil chemistry changes by produced water.

The on-site investigation of two land application sites No. 139 (discharging for two years) and No. 64 (discharging for six months) was conducted to determine litter and plant elemental concentrations (Fig. 6). Water application rates were initially 400 barrels per day (BPD) and 308 BPD, respectively and had declined to 21 BPD and 116 BPD, respectively. In addition, Site No. 151 was used as a natural revegetation study site. Initially all vegetation within the treatment area was dead (24 hour continuous application at >149 BPD). Within 2.5 months after stoppage, the area had revegetated without remediation.

Greenhouse studies were conducted to determine the effects of (1) chlorides upon plant yields, (2) effects of water application management and (3) effects on new plant growth on soils previously irrigated with produced water. Three studies were conducted utilizing sorghum sundangrass and produced water at various concentrations of chlorides. One study was performed utilizing continuous irrigation and intermittent irrigation with two harvest (Fig. 7), an additional study performed using soils that had previously been irrigated with produced water utilizing various irrigation treatments and only one harvest (Fig. 8) and one study of plant recovery response with soils previously irrigated continuously with various concentrations of produced water (Fig. 9).

Results of the study indicated that produced water containing up to 1100 mg/l TDS (approximately 450 mg/l) may improve plant growth if the irrigation system is properly managed. Additionally, plant response depends not only upon salinity but the length of time the soil is saturated with water. No exact threshold TDS was established for plant growth. However, under all methods of irrigation plant growth will begin to decrease at ± 1280 to 2560 mg/l TDS and a greater reduction was found for continuously saturated soils. Soil structure was studied for effects by produced water by evaluating the chemical equilibrium between produced water and soil absorption and the adsorption capacity of the soil. Equilibirum Ion Exchange testing indicated that no salt buildup was occurring on sites with applied water containing TDS levels of 2800 mg/l or less (1,700 mg/l chloride). It is reasoned that applied water will leach salts when applied in excess of plant uptake and water holding capacity.

Soil-water interactions were further studied using a vacuum extractor to determine the equilibrium between soil and produced water with a TDS content of 2800 mg/l. The results show that the cation exchange sites of the soil are nearly saturated with Na^+ after one (1) soil volume of applied water leaches through. This would equate to 16" of water applied per unit area on soils with a depth of 20" (with 20% rock fragments). (Fig. 10). Correction of this was additionally studied and results yield that only 60% of Na^+ was removed with the application equivalent of 320" of distilled water per unit area. However, water saturated with gypsum displaced essentially all Na^+ with the equivalent of 64" of solution per unit area. (Fig. 11). However, only 1/2 column volume (approximately two (2) pore volumes) of distilled water was necessary to return the soil the low hazard range of conductivity for plant growth (Fig. 12).

Due to the amounts of water being applied at rates of 1"-2" per day/unit area, it would be necessary to move the irrigation system on a regular schedule of 2 weeks or a system regulated to be off for a 48 - 72 hour interval between applications. This was verified with field observations.

From the research done by Auburn University, it was apparent that neither the soil structure or the native vegetation would be severely impacted on a long term basis after application ended. However, it was determined that neither the soil nor the plant uptake of chlorides was sufficient to significantly limit the chlorides from being leached through the soil.

A preliminary assessment of groundwater was undertaken for Jefferson, Tuscaloosa and a portion of Walker Counties, Alabama, by the Geological Survey of Alabama in cooperation with the University of Alabama. This assessment identified the extent of groundwater in this area and to a limited extent water quality. It was shown that the major source of useable water for this area could be classified as groundwater with the major recharge being from surface waters and rainfall(11).

CURRENT STATUS

To provide additional control of water quality, Amoco was an active participant in the development of a unique industry monitoring system installed on the Black Warrior River by Warrior Basin Environmental Cooperative, Inc. (WEBCI). WEBCI was formed by eleven coalbed methane development companies to monitor the Black Warrior River, draining some 4,000 square miles, for flow and chlorides to assure maintenance of water quality well below the limits established by the Safe Drinking Water Act.

The alternative of disposal through underground injection was studied by Amoco and others for this area. Geological information in the area concluded that no suitable strata was available for injection of produced water. In review of the River Gas Corporation's Blue Creek Coal Degasification field adjacent to Amoco's Oak Grove Field, Joiner concluded "geologically, that there is no suitable subsurface disposal zone in the vicinity of this field" (13).

A major concern that until recently was only minimally addressed was non-point source pollution. Non-point source pollution in this area consists primarily of sedimentation in storm runoff (erosion). Due to the necessary construction of roads, well sites, pipelines, and rugged terrain, erosion is induced during normal rainfall. To control this source of pollution, it is necessary to develop a 'Best Management Practices Plan' which details an approach to erosion control and construction techniques. By doing so contractors and others involved in the installation and maintenance of facilities become directly involved in accomplishing the control of pollution.

This type of plan should include (1) criteria for siting roads, pipelines and well pads; (2) erosion measures - hay bales, silt fences, rip rap, stream side management zones, mulching, etc. (3) construction techniques - slope controls, terracing, wing ditches, diversion barriers, etc. In addition, this plan details stream crossings for pipelines and roads.

Amoco and other operators have established an industry organization, the Coalbed Methane Association of Alabama (CMAA). This organization provides industry input into regulation development and provides a convenient avenue for transfer of technology, information, methodology and regulation.

The combination of the studies performed indicated that the better environmental control could be performed utilizing the NPDES permitted stream discharge. This system allows for monitoring of effluent and downstream concentration of contaminants for management judgements of environmental concerns. Also, additional scientific studies have been performed that further defined the toxicity limits of freshwater organisms to chlorides. To perform land application for an extended period of time, it would be necessary to perform a site specific groundwater study to predict and monitor for potential chloride contamination.

Exploitation of natural resources is necessary for the continued development of industry and life styles as expected by citizens of the United States. However, this exploitation cannot exist with exploitation of the environment. As projects are approached, evaluation of environmental impacts on and by the project are necessary. The resulting management plan may include some of the items discussed, but should not be limited to these. As the project is undertaken and development begins, it is necessary to continue to evaluate the effects on the environment and be willing to alter the course. These changes may result in higher costs to the project, although in some instances the change may result in a positive economic impact.

Through proper management of the project and the generation and disposal of waste, development can proceed without damage to the environment.

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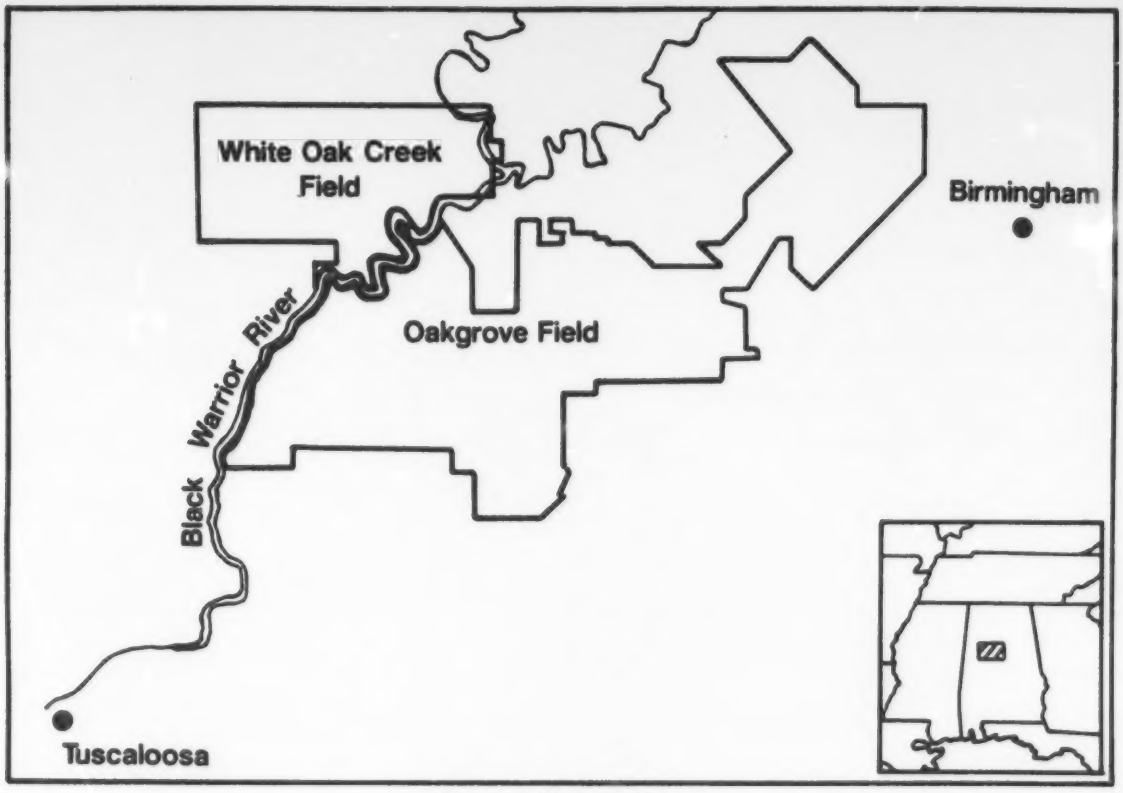

Area of Operations
Figure 1

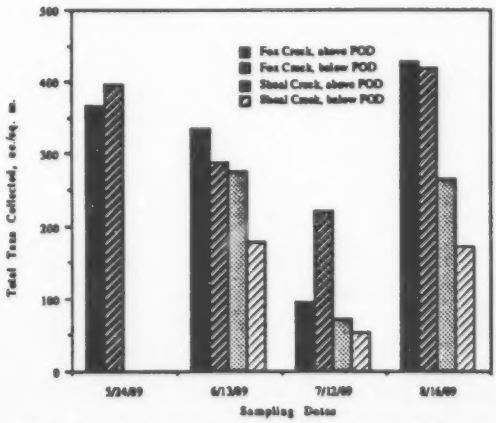

Figure 2 - Total Macro-invertebrate Taxa Collected, Primary Sites after Marinello et al. (10)

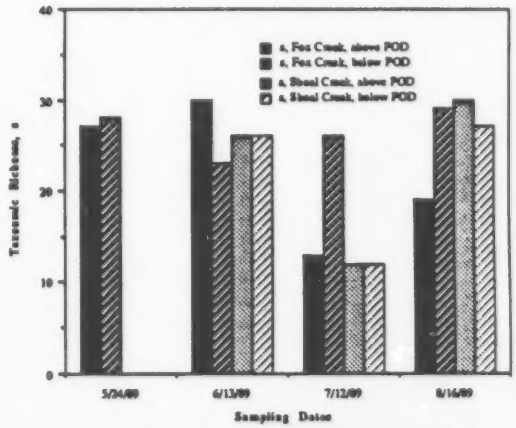

Figure 3 - Taxonomic Richness, Primary Sites after Marinello et al. (10)

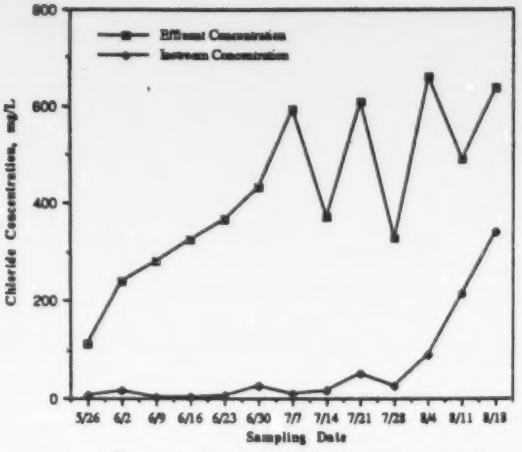

Figure 4 - Shoal Creek Chloride Concentrations, after Marinello et al. (10)

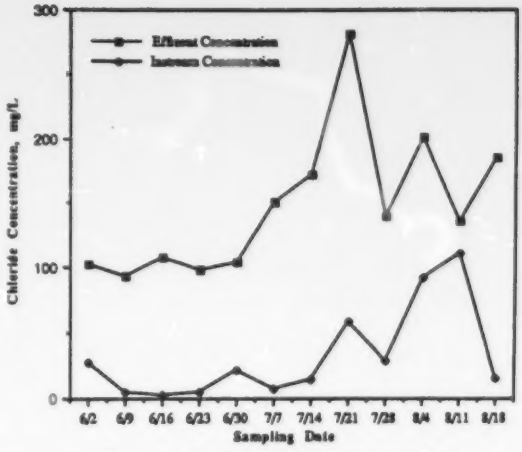

Figure 5 - Fox Creek Chloride Concentrations, after Marinello et al. (10)

Figure 6 - Chemical analysis of vegetation samples Site No. 64, after Mullins, et al (11)

Area	Sample Type	Ca	K	Mg	P	Cu	Fe	Mn	Zn	Na
		g/Kg				mg/Kg				
Control[1]	Grass	3.5	5.1 [a]	2.5 [a]	0.9 [a]	6 [a]	95 [a]	331 [a]	17 [a]	323 [a]
Treated[2]	Grass	4.0	2.8	0.9	1.9	15	17725	695	37	8287
Control	Surface Litter	7.5[a]	0.7	1.3 [a]	0.5 [a]	8 [a]	1230 [a]	860 [b]	42 [a]	157 [a]
Treated	Surface Litter	13.9	0.6	2.2	0.8	14	8490	1169	62	8970
Chemical analysis of vegetation samples Site No. 139										
Control	Dogwood	20.9	8.5	3.2	0.8	4	91	22	4	100
Treated	Dogwood	12.2	6.4	2.5	0.9	4	96	16	4	190
Control	Hickory	20.9	8.7	4.6	1.4	11	106	583	63	250
Treated	Hickory	6.9	10.4	2.9	1.2	9	100	427	21	540
Control	Oak	15.9	7.2	1.5	0.9	6	87	255	6	240
Treated	Oak	8.2	7.3	1.9	0.8	6	51	211	14	210
Control	Surface Litter[3]	21.0	1.3	2.1	0.8 [a]	11 [a]	3818 [a]	1255 [a]	66 [a]	410 [a]
Treated	Surface Litter	19.8	1.1	2.0	1.1	22	9449	976	62	9087
Control	Honeysuckle	18.2	22.6	6.7	1.4	5	101	239	27	125
Treated	Honeysuckle	5.0	19.1	2.6	1.7	7	78	59	10	13795

[1]Control = areas at locations that had not been affected by produced water.
[2]Treated = areas at same location that had received produced water.
[3]Surface litter was the only sample type where enough subsamples were collected for statistical analysis.
[a]Control area is significantly different from the treated area at the 0.05 level of probability.
[b]Control area is significantly different from treated area at the 0.10 level of probability.

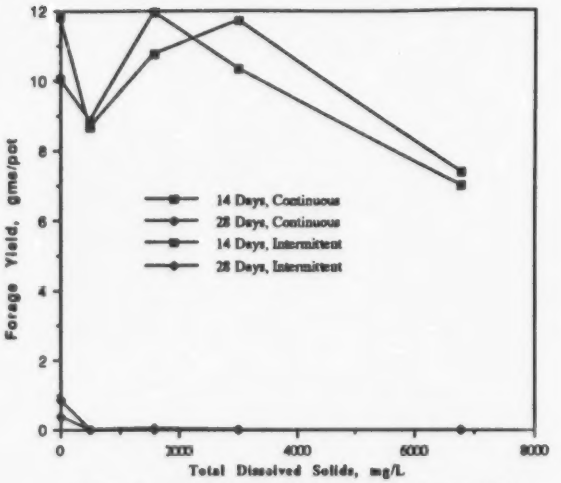

Figure 7 - Effect of Irrigation Method on Forage Yield, 14 Day Interval Harvests with Various Waters (First Study) after Mullins et al. (11)

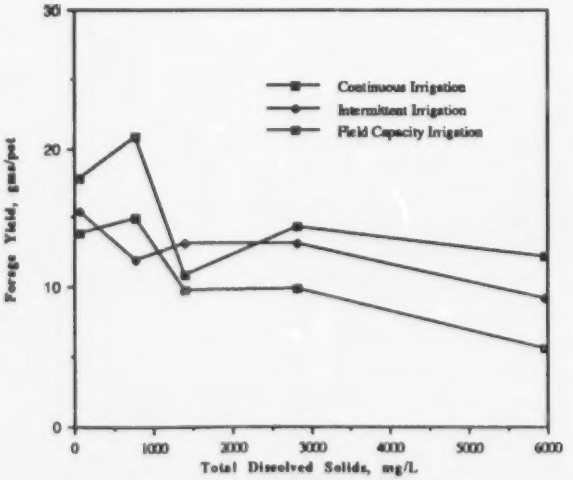

Figure 8 - 30-Day Forage Yields for Various Irrigation Methods and Waters, Single Harvest after Mullins et al. (11)

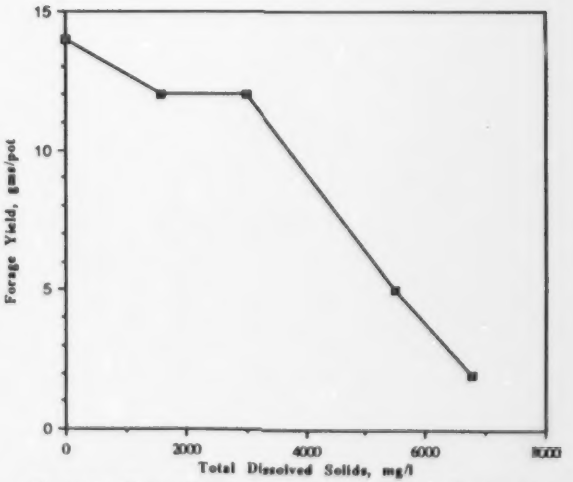

Figure 9 - Forage Recovery Response of Soils, Harvest at 30 Days (after 28 Day Pre-treatment with Continuous Irrigation) after Mullins et al. (11)

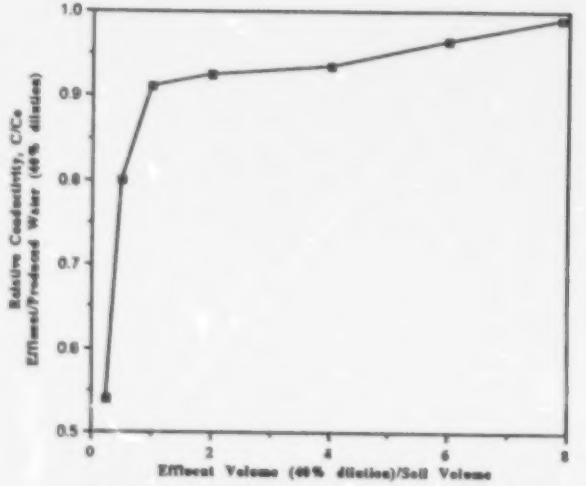

Figure 10 - Relative Effluent Conductivity, Site 59 Soil after Mullins et al. (11)

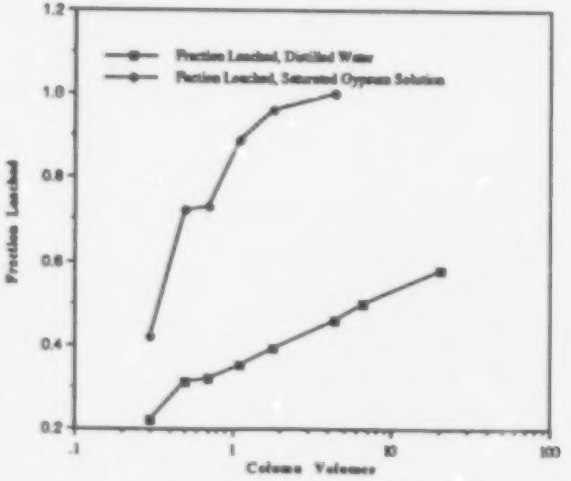

Figure 11 - Fraction Na^{+} Leached, Site 151 Soil after Mullins et al. (11)

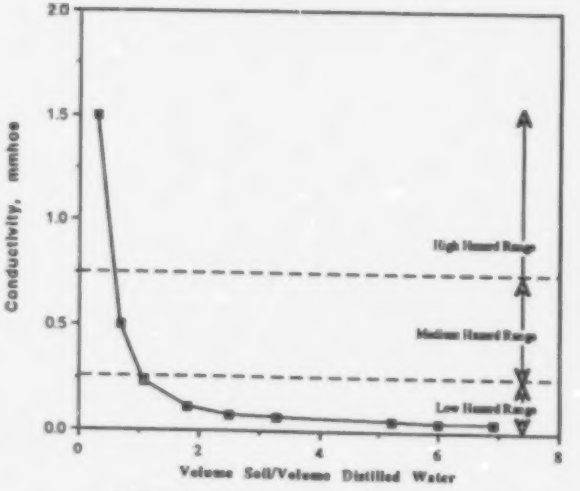

Figure 12 - Leachate Conductivity, Site 151 Soil after Mullins et al. (11)

DRILLING WASTE LANDSPREADING FIELD TRIAL IN THE COLD LAKE HEAVY OIL REGION, ALBERTA, CANADA

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Introduction

Drilling associated with the oil industry generates wastes that must be disposed of in an environmentally safe manner. Drilling in the Cold Lake region of Alberta, Canada generates a number of different types of wastes dominated by freshwater gel wastes and potassium chloride (KCl) and sodium chloride (NaCl) types to a lesser extent. Landspreading is one of the disposal options available and loading rate guidelines have been established by the Alberta Energy Resources Conservation Board (7).

The Alberta Research Council has conducted research into sampling and characterization strategies to characterize major drilling waste types on a province wide basis. Greenhouse work has been conducted to assess the impact of these wastes on soils and plants. Field studies designed to validate and calibrate the greenhouse results were seen as the next step required to assist in defining maximum or tolerable loading on the basis of waste type.

As a result a joint program was developed by the Alberta Research Council and ESSO Resources Canada Limited and undertaken in the Cold Lake area in 1988. This paper describes the results of the research conducted in 1988 and 1989.

Objective

The objective of the experiment is to identify the impact of different loading rates of KCl, NaCl, and freshwater gel drilling wastes landspread on Luvisolic (Cryoboralf) soils commonly occurring in the Cold Lake region of Alberta. Emphasis was placed on determining maximum tolerable loading rates.

Materials and Methods

Experimental plot establishment

The plot site ultimately selected for the experiment was characterized by a commonly occurring Luvisolic (Cryoboralf) soil within the ESSO Cold Lake lease area and also a significant portion of northern Alberta. Plot site preparation included cleanup of the area and plot staking.

All plots were sampled prior to waste application to provide baseline information so that comparisons could be made to the results of subsequent sampling events. A composite sample from five-sample locations was obtained for the 0 to 15 cm depth interval at each of the plots. Additional samples were obtained from the 15 to 30 cm, 30 to 60 cm, and 60 to 90 cm depth intervals at some of the plots.

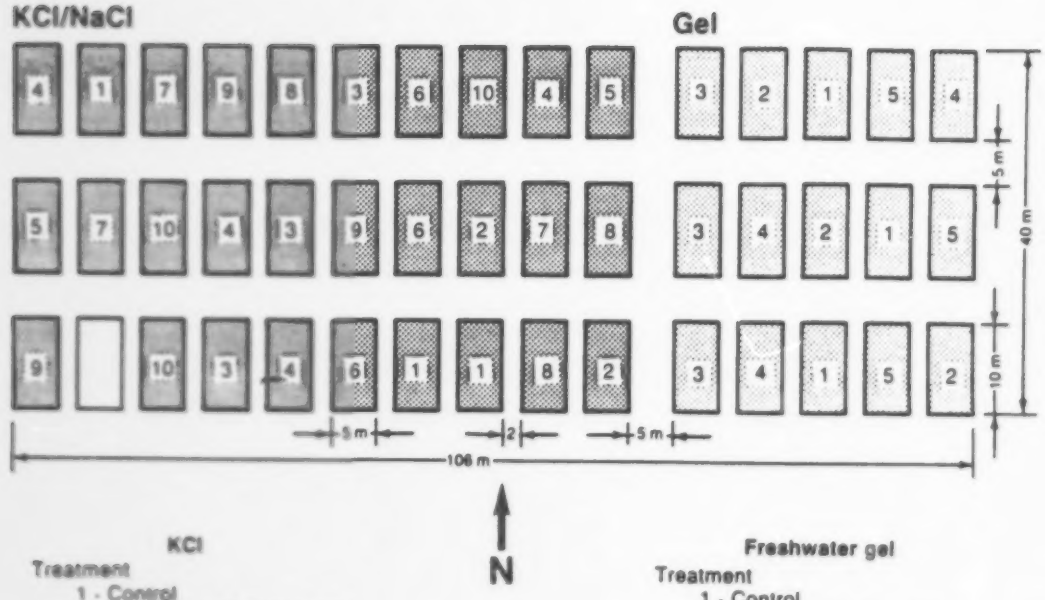
All plots were rototilled and then the wastes were applied. The waste was removed from the respective sumps by a large backhoe and loaded into a 11 m^3 cement truck. The cement mixer was constantly revolving as the loading proceeded so that the material was thoroughly mixed. When the truck was filled a sample was removed for analytical purposes.

The waste was spread by pail to maintain uniform application rates at each of the plots. Barrels having a 200 L capacity were used for unloading the waste from the truck and 10 and 20 L pails were then utilized for spreading. The maximum rates of freshwater gel required the application of 200 pails of waste. Some raking was required to maximize uniformity and to get the waste materials to the extreme margins of the plots. On the other hand extreme care was required in spreading the relatively small volumes of 40 L per plot. The resulting experimental design is illustrated in Fig. 1.

Following waste application the materials were incorporated into the top 15 cm of the soil utilizing a tractor mounted rototiller unit. For the freshwater gel plots receiving the higher application rates some time was left between passes or cultivations to allow for some drying to occur.

All plots were seeded during the period July 11 and 12, 1988. Brome grass was hand broadcast at the rate of 75 kg/ha and 300 kg/ha of 16-20-0 fertilizer was applied. The plots were hand raked to incorporate the seed and fertilizer into the soil surface.

Soil sampling and selected tissue sampling was completed in mid-September of 1988. Each plot had soil samples taken in the 0 to 15 cm interval. In some plots a composite sample of five locations was obtained and in selected plots 10 individual samples were collected to assess the degree of variability of the chemical parameters. Sampling of the 15 to 30 cm, 30 to 45 cm, 45 to 60 cm, and 60 to 90 cm intervals was also completed in several plots. Plant tissue was collected from each of the freshwater gel amended plots and 12 of the KCl and NaCl amended plots. Vegetation cover on the remaining plots was not adequate to obtain an appropriate sample.



KCl

Treatment

1 - Control
2 - Minimum application rate
3 - Application rate > Trt.2
4 - Application rate > Trt.3
5 - Maximum application rate

NaCl

Treatment

6 - Control
7 - Minimum application rate
8 - Application rate > Trt.7
9 - Application rate > Trt.8
10 - Maximum application rate

Freshwater gel

Treatment

1 - Control
2 - Minimum application rate
3 - Application rate > Trt.2
4 - Application rate > Trt.3
5 - Maximum application rate

Figure 1. Schematic diagram of experimental design.

In 1989 tissue samples were collected in the latter part of June at the time of plot harvest for yield determination. Tissue material was collected from several locations within each plot and the samples transported to the laboratory in paper bags, and dried at 70°C for 24 hours prior to grinding and analysis.

The harvesting was done by use of a lawn mower so that all plant material from each plot could be removed. Harvesting the entire plot removed any bias from randomly selecting smaller unit areas within each plot and the use of a mower set at a given height ensured, to the greatest extent possible, uniformity in harvest.

All material from each plot was weighed to determine the fresh weight. A subsample of this fresh material was weighed and transported to the laboratory for drying so that a dry weight could be determined for each plot.

Soil sampling was completed in mid-August of 1989. Samples were collected in the same manner as done in 1988 to allow for comparison of results.

Methods of analysis

Water content of sump solid samples was calculated after drying at 105°C for 24 hours, pH was measured in a paste (6) and in a 2:1 slurry of 0.01 M $CaCl_2$ (17). Total carbon content was measured with a LECO CR12 carbon analyser (11), $CaCO_3$ equivalent by acid dissolution (4) and acid neutralizing capacity by addition of 0.5 M HCl, and back titration with 0.25 M NaOH (methods 1.004 and 1.005 (3). Saturated pastes were prepared according to the USDA Soil Salinity Laboratory method (20; 18); were extracted and the extracts filtered through a 0.45 mm filter and analysed for pH, electrical conductivity, alkalinity, chloride, and for soluble salts (Na, K, Ca, Al, Cr, Fe, V, Ti, Cd, Cu, Pb, Zn, Mn, Mg, Li, Sr, B, Ba, P, S, Mo, Ni, Se, As, Co, Si) using an ARL model 3400 simultaneous Inductively Coupled Plasma Atomic Emission Spectrometer (ICP-AES). Cation exchange capacity (CEC) and extractable cations of the sump solid samples were determined by extraction with a normal (1 M at pH 7.0) ammonium acetate solution (10), where NH_4 ions were determined by a Tecator Kjeltec Auto 1030 Analyser distillation and titration unit and the exchangeable ions by the ICP-AES. The particle size analysis was done using a simplified hydrometer method (9).

DTPA-NH_4HCO_3 extractable elements (Fe, Cd, Cu, Pb, Zn, Mn, Ca, Mg, Na, K, B, P, Mo, Ni, Se) were determined by the method of Soltanpour and Workman (19). Total elemental analysis of the solid sump samples was done by digestion in a CEM microwave digestion system. The procedure used included ashing the material overnight in a 425°C muffle furnace, digestion in a teflon bomb in the microwave oven with 1.5 mL HNO_3, 4.5 mL HCl, and 10 mL HF for 10 min at 100% power, 20 min at 50% power, and 10 min at 100% power. The digested solutions were transferred and made up with saturated H_3BO_3 to 50 mL, and the metal concentrations measured using ICP-AES. Minerals were identified in the sump solid samples using a Phillips X-ray diffraction (XRD) instrument.

Oil content in the samples was measured gravimetrically by soxhlet extraction with methylene chloride (16). The methylene chloride extracts were separated into acid, base and neutral fractions by extracting with HCl or NaOH, and submitted for analysis by gas chromatography mass spectroscopy (GC-MS).

The grass samples were digested with a concentrated HNO_3 - $HClO_4$ acid mixture in a teflon bomb heated in a CEM microwave digestion unit and the solution concentration of Al, Fe, Zn, Mn, Ca, Mg, Na, K, Sr, P, Ba, Mo, B, S, Si, and As measured by ICP-AES and Cd and Pb by graphite furnace atomic absorption. Chloride content was determined by the sodium nitrate extraction procedure of Gaines et al. (8).

Results and Discussion

Data pertinent to the properties of the soils prior to waste application and subsequent to waste application were reported by Macyk et al. (13).

The plot treatments illustrated in Fig. 1 represent various application rates of waste based on chloride concentration. Initially, the objective of the experiment was to apply 0(control), 450 kg Cl/ha, 900 kg Cl/ha, 1800 kg Cl/ha, and 3600 kg Cl/ha. It was not possible to achieve the suggested rates using the freshwater gel because of its low chloride content relative to the other waste types. Levels very close to the target values were achieved with the use of the KCl and NaCl materials. Table 1 provides the chloride levels applied for each of the treatments.

TABLE 1
Waste application treatments

Treatment	Chloride addition (kg Cl/ha)
Freshwater gel 1	0
Freshwater gel 2	15
Freshwater gel 3	30
Freshwater gel 4	60
Freshwater gel 5	120
KCl 1	0
KCl 2	500
KCl 3	1000
KCl 4	2000
KCl 5	4000
NaCl 6	0
NaCl 7	350
NaCl 8	700
NaCl 9	1400
NaCl 10	2800

Plot yield

Observations relative to the brome grass growth on the various plot treatments were made throughout the growing season. The freshwater gel treated plots had the best growth overall with the FW 2 and FW 3 treatments having better growth than the FW 1 (control) treatment. The FW 4 and FW 5 treatments had the poorest growth and appeared the most pale green or chlorotic in color. Germination appeared to be affected by the application of the KCl and NaCl waste materials, particularly the KCl 5 and NaCl 10 treatments. These plots contained far fewer plants than plots with lower application rates, however, the plants present appeared much larger and mature than the plants in the other treatments.

Table 2 provides a comparison of the mean yield values for the treatments within each waste type. There were apparent differences but no significant differences in yield between the treatments for each of the waste types.

For each of the waste treatment types the yield obtained for the lower waste application rates exceeded the yields obtained in the respective control treatments. Rates 2 and 3 for the freshwater gel plots and the NaCl plots exceeded the control yield. The KCl rate 2 treatment exceeded the control yield value. For each of the waste types the maximum application rate

TABLE 2

Comparison of the mean yield values for the field trial plots

Waste	Rate	N	Yield (g)
Freshwater	1	3	5750a
Freshwater	2	3	7660a
Freshwater	3	3	5850a
Freshwater	4	3	4230a
Freshwater	5	3	2780a
KCl	1	3	2240a
KCl	2	3	2680a
KCl	3	3	1870a
KCl	4	3	1630a
KCl	5	3	1380a
NaCl	6	3	2740a
NaCl	7	3	2800a
NaCl	8	3	3010a
NaCl	9	3	2280a
NaCl	10	3	1090a

* Treatment means of each waste in any one column not followed by a common letter are significantly different at 0.01 probability by Tukey's Studentized Range (HSD) Test.

resulted in the lowest yield. Similar trends were observed relative to yield of brome grass grown in freshwater gel, KCl, and NaCl waste and soil mixtures in the greenhouse (14).

Field plot soil properties

A total of 77 soil samples were collected at the 45 plots prior to waste application and 207 samples were collected in mid-September 1988 approximately two months following waste application and incorporation (13). A total of 207 samples were collected in mid-August 1989.

The samples obtained in 1988 were analysed for several chemical and physical properties, soluble ions in saturated paste extracts, plant available trace elements (DTPA extractable), and total elemental content (13). The samples obtained in 1989 were analysed for some chemical properties as well as soluble ions in saturated paste extracts and total elemental content to assess the extent of change in salt concentration (EC and chloride levels) and elemental levels at the various depths in the different treatments.

Chemical properties

The Alberta Soils Advisory Committee (1) suggests that no limitations to plant growth occur at pH levels in the surface soil of 6.5 to 7.5, and that slight limitations occur at levels of 5.5 to 6.4 and 7.6 to 8.4. The mean pH values in the 0 to 15 cm depth interval of the freshwater gel plots ranged from 6.5 to 7.0 prior to waste application which indicates that these soils exhibited no limitation to plant growth. Following waste application, the FW 4 and FW 5 treatments had pH values that could result in slight limitations to plant growth. The difference of 0.1 pH units between 1988 and 1989 was minor.

The mean pH values in the 0 to 15 cm depth interval of the KCl plots ranged from 6.7 to 7.2 prior to waste application and 7.2 to 7.4 following waste application. These values indicate that the KCl waste additions did not result in pH values that could be considered limiting to plant growth.
The mean pH values in the 0 to 15 cm depth interval of the NaCl plots ranged from 6.6 to 7.0 prior to waste application and 6.9 to 7.6 following waste application. These values indicate that the NaCl waste additions did not result in pH values that could be considered limiting to plant growth except for the NaCl 10 treatment which had a mean pH of 7.6 in the fall 1988 and 7.4 in the fall of 1989.

Saturated paste extract data

These data indicate the magnitude of the soluble components in a saturated solution of these materials and can be used to assess the suitability of these materials for plant growth and the possibility of trace element transport. Table 3 provides more detailed data for EC, and Cl for the individual depths within the various treatments. The data include values for the soils sampled in May 1988 prior to waste application and then in September 1988 and August 1989.

TABLE 3

Mean values for EC and Cl for the various treatments

Waste	Rate	Depth (cm)	EC			Cl		
			Pre	Post	1989	Pre	Post	1989
Freshwater	1	0-15	0.62	0.76	1.06	20.3	25.1	12.2
	2	0-15	0.51	0.91	1.17	18.7	22.3	19.8
	2	15-30	-	0.53	-	-	11.7	-
	3	0-15	0.59	1.14	1.37	17.8	33.0	22.4
	3	15-30	0.25	0.36	0.93	15.9	15.8	19.3
	4	0-15	0.59	1.10	1.11	18.2	36.3	16.0
	4	15-30	0.45	0.58	0.49	8.8	15.9	7.9
	4	30-45	0.36	0.35	0.39	11.3	11.6	6.9
	4	45-60	0.36	0.35	0.39	11.3	11.6	6.9
	5	0-15	0.58	1.39	1.44	16.3	40.0	32.1
	5	15-30	0.31	0.80	0.73	9.6	37.9	13.5
	5	30-45	0.26	0.32	0.54	8.9	15.8	11.0
	5	45-60	0.26	0.32	0.46	8.9	15.8	9.9
KCl	1	0-15	0.51	0.86	0.72	19.1	22.7	13.1
	2	0-15	0.54	1.20	1.09	20.6	396.0	118.8
	3	0-15	0.52	2.60	2.02	20.3	740.0	403.0
	4	0-15	0.61	2.87	2.75	22.7	1070.0	863.0
	4	15-30	0.31	0.47	1.09	11.5	69.1	386.0
	4	30-45	0.41	0.80	0.72	7.9	281.1	221.0
	4	45-60	0.41	0.54	0.72	7.9	52.5	43.2
	4	60-90	0.23	0.13	0.09	6.0	17.9	10.2
	5	0-15	0.47	3.54	1.59	18.2	3135.0	353.0
	5	15-30	0.55	2.51	-	17.6	889.0	-
	5	30-45	0.19	1.65	-	6.7	555.0	-
NaCl	6	0-15	0.53	0.70	0.89	25.9	35.6	37.2
	7	0-15	0.57	1.95	1.20	22.2	480.0	151.0
	7	15-30	-	-	0.58	-	-	75.0
	8	0-15	0.61	1.38	1.80	20.8	870.0	331.0
	8	15-30	0.55	0.49	2.01	13.1	85.1	496.5
	8	30-45	0.34	0.28	0.43	9.1	90.3	51.0
	8	45-60	0.34	0.27	0.33	9.1	9.7	41.1
	8	60-90	0.36	-	-	6.9	-	-
	9	0-15	0.60	3.01	1.80	23.4	876.0	325.0
	9	15-30	0.39	-	-	19.2	168.0	307.0
	9	30-45	0.21	-	-	12.8	114.2	135.4
	9	45-60	0.21	-	-	12.8	188.2	116.5
	9	60-90	0.16	-	-	16.4	144.1	-

TABLE 3 (Concluded)
Mean values for EC and Cl for the various treatments

Waste	Rate	Depth (cm)	EC			Cl		
			Pre	Post	1989	Pre	Post	1989
NaCl	10	0-15	0.51	7.27	5.36	24.4	3352.0	1728.0
	10	15-30	0.46	0.96	-	14.6	206.1	539.0
	10	30-45	0.25	0.31	-	7.5	42.6	306.0
	10	45-60	0.25	0.22	-	7.5	25.4	192.0
	10	60-90	0.12	0.11	-	8.2	20.2	454.0

Pre = Sampled prior to waste application; Post = Sampled September 1988; 1989 = Sampled August 1989.

These data illustrated the changes that occurred resulting from the waste application and the subsequent change with time and can be compared to existing criteria to assess soil quality or the extent of limitation to plant growth that may occur.

Electrical conductivity (EC) values

The Alberta Soils Advisory Committee (2) suggests that no limitations to plant growth occur at EC levels of 0 to 2 dS/m, slight limitations occur at 2 to 4 dS/m, moderate limitations occur at 4 to 8 dS/m, and severe limitations occur at values greater than 8 dS/m.

The mean EC values for all plots and all depths prior to waste application were well below 1.0 dS/m with the highest values of about 0.6 dS/m in the 0 to 15 cm depth interval (Table 3). This indicated that on the basis of EC soils presented no limitation to plant growth. Following the application of waste materials the soil EC values increased at all locations. In the freshwater gel plots the maximum EC values were in the 1.39 to 1.44 dS/m range. These values suggest that the EC levels of the plot soils would present no limitation to plant growth.

Changes in EC levels in the KCl plots were greater than those in the freshwater gel plots. For all treatments the EC values in the 0 to 15 cm depth interval decreased from the fall of 1988 to August 1989. Concomitant with this were increases in EC levels in the depth intervals below the surface 15 cm. This indicates the degree of leaching that occurred. On the basis of the soil quality criteria described above, treatments 3, 4, and 5 would have had slight limitations to plant growth on the basis of EC for the 0 to 15 cm depth in the fall of 1988 with a reduction in limitation by the fall of 1989.

In the NaCl plots the mean EC values were somewhat higher than in the freshwater gel and KCl plots. The trends regarding the changes that occurred with time are similar to the freshwater gel and KCl treatments. The highest application rate of NaCl waste resulted in EC levels that imply a moderate

limitation to plant growth. The mean EC value for the NaCl 10 treatment was 7.27 dS/m in the fall of 1988 and decreased to 5.36 dS/m by the fall of 1989.

Chloride values

Maas (12) indicated that the maximum chloride content that could be present in saturated extracts without loss of yield in grasses ranges from 1000 to 2600 ppm. Following the application of waste materials the Cl values increased at most depths in all plot treatments. The smallest change in Cl content occurred in the freshwater gel plots simply because of the low Cl levels in the gel wastes applied.

Leaching of the Cl was evident by the change that occurred between 1988 and 1989. Using the criteria of Maas (12) indicates that the chloride concentration in the plots will have no negative impact on plant growth.

The KCl treatments had considerably higher Cl additions than the freshwater gel treatments. Using the value of 1000 ppm Cl as the level in soil that begins to impact plant growth suggests that some limitation was possible for treatment KCl 4 and more so for treatment KCl 5 in the fall of 1988. The mean Cl values for the 0 to 15 cm depth decreased in 1989.

The trends associated with Cl levels in the KCl waste treated plots were similar for the NaCl waste treated plots.

Tissue Analysis Data

The total elemental content of the brome grass tissue collected in 1988 and 1989 was determined. The 1988 data obtained represents an incomplete set, simply because the vegetation cover in all plots was not adequate to provide a sample particularly in the case of the KCl and NaCl waste amended plots.

The effect of the addition of drilling waste on the elemental enrichment of the affected plants can be demonstrated by the enrichment ratio (ER). The ER of a chemical element is calculated by dividing the elemental concentration of the waste - affected plant tissue by that of the unaffected plant tissue.

The tissue from the treated plots exhibited elevated levels of chloride, sodium and to a lesser extent copper in comparison with the tissue from the control plots. Boron levels increased two-fold over control levels for the FW 5 treatment in 1988, however, they were down to control levels in 1989.

Copper levels in the tissue were higher in 1989 than in 1988. Tissue levels of 1.0 to 5.1 ppm and 5.2 to 18.0 ppm copper are considered deficient and normal, respectively. Tissue grown in the control plots had copper levels at about the mid-point of the deficient range. Addition of waste resulted in increased tissue copper values with some of the values occurring in the normal range for grasses.

Sodium levels in the tissue increased with increasing application rate of the different wastes, particularly the NaCl material. Substantial differences in the uptake of Na between 1988 and 1989 were evident from the ER values of 29.0

vs 2.3 for the NaCl 9 treatment, respectively. This is related to the fact that the sodium was leached downward from the zone of waste incorporation and out of the currently established root zone. Normal and excessive levels of sodium in grasses are 300 to 1100 ppm and 3200 to 43700 ppm, respectively. On the basis of these criteria, it was apparent that the normal levels were not exceeded, and that for many of the treatments were not even achieved.

Tissue chloride values ranged from 2.89 mg/g (2890 ppm) to 6.01 mg/g (6010 ppm). Chapman (5) reports an intermediate range of 7000 ppm and a high range of 8700 to 15400 ppm for chloride in grasses. Using these values as a guideline suggests that the application of all wastes resulted in high levels of chloride in the tissue in 1988 particularly the tissue from the KCl and NaCl treated plots. The chloride levels in the tissue in 1989 were considerably lower than those in 1988. The decrease in tissue chloride levels in 1989 is directly related to the decrease in soil/waste chloride levels. All values reported for 1989 were below the intermediate level of 7000 ppm, reported by Chapman (5).

The concentration of potassium in the tissue did not change at all for all treatments except for the KCl 4 plots, despite the fact that the KCl treated plots received a high concentration of potassium especially at the higher application rates. Magnesium uptake declined with increased waste application rate and in particular with the NaCl waste. It is likely that the levels of other cations were in part responsible for the lowered uptake of magnesium by the brome grass.

Conclusions

Observations made and results obtained pertinent to the field study in 1989 form the basis for the preliminary conclusions presented herein. The application of the different wastes at varying rates had both positive and negative impacts on the soils and the plants grown thereon.

The freshwater gel treatments reduced yield below control levels for the FW 4 and FW 5 plots, and the resultant soil/waste mixtures exhibited pH levels that might exhibit a slight limitation to plant growth. These results suggest that the application of freshwater gel, to the levels of treatments FW 2 and FW 3, presented no limitation to the plot soils or the plants grown thereon and, in fact, enhanced the soils and plant growth to some extent.

Similar trends were observed for the KCl and NaCl treatments, however, the impacts were more marked for some of the parameters. From a yield standpoint, the application of KCl wastes resulted in a negative impact for the KCl 3, KCl 4, and KCl 5 treatments. From a soil quality standpoint in 1989, slight limitations due to EC were evident for the KCl 3, KCl 4, and KCl 5 treatments and a slight limitation due to Cl.

The NaCl 7 treatment resulted in essentially no negative impact on soil quality and enhanced plant growth. Depending upon time elapsed following waste application, the NaCl 8, NaCl 9, and NaCl 10 treatments had slight to severe impacts on soil quality (EC, SAR, Cl levels). The impact was lessened with time.

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DRILLING WASTES MANAGEMENT FOR ALASKA'S NORTH SLOPE

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Introduction

The primary state agency in Alaska for regulating the disposal of drilling waste is the Department of Environmental Conservation. The department uses its solid waste, water quality and waste water regulations for oversight of these wastes. Tools for managing include facility plan reviews, waste discharge permits and onsite inspections. These activities are done through the Fairbanks office, located 400 miles from the major oil fields of Prudhoe Bay.

In the early 1980s department presence in the oil fields was as little as 10 person-days a year. This was changed when the North Slope District Office was formed in 1983. Office space was leased in Deadhorse, the population center for oil development on the North Slope. Field presence is now over 200 person-days a year.

With increased monitoring, there was improved documentation of the effectiveness of waste management practices of drilling wastes in the oil development area of the North Slope. Wastes were stored in pits made of berms of pit run gravel placed directly onto the tundra. The tundra served as floor; no lining materials were used. The dikes were believed to have frozen cores which were impermeable. What was found was that the gravel rapidly thawed and subsequently leaked. During the wind swept winter months extensive snow drifts accumulated in the pits. When they melted the pits overflowed, and hydraulic head caused leaching and rupture of the dikes.

The department reacted to these observations with new regulations that were promulgated in the summer of 1987. The intent of these regulations was to require total containment of drilling wastes, encourage consolidation of disposal sites, encourage alternatives to surface disposal of wastes and, most important, encourage waste minimization. This was accomplished by setting minimum standards for reserve pits, requiring fluid management plans to reduce fluid levels that promote leaking, and limiting the disposal of materials incompatible with pit design, such as freeze depressants in pits that rely on permafrost containment.

Minimum monitoring for sites is outlined in the regulations, which is providing the beginnings of a data base on pit performance.

Realization of unacceptable practices has caused a renaissance of ideas to improve the handling of drilling wastes. This report discusses the development status of these ideas, regulatory schemes that the department is using, and concerns the department has for success of options being tried. Practices that have been tried and are being evaluated are waste reduction, injection of drilling wastes, deep hole burial using permafrost containment, shallow hole burial using permafrost containment, and treatment of waste and subsequent use as construction material for roads and pads.

Waste Reduction Techniques

Waste reduction can be looked at as the reduction in volume of wastes needing disposal or the reduction of waste toxicity.

Toxic additives can be introduced throughout the drilling process. Drilling fluids are used to control pressures, flush cuttings to the surface, seal the well casing, lubricate and cool the drill bit, and transmit hydraulic horsepower to the bit (1). Exotics that are added to the drilling system that potentially add toxicity include lubricating agents, emulsifiers, coagulants, pipe dope containing lead, biocides used to prevent reservoir contamination by sulphur reducing bacteria, solvents for removing paraffins, corrosion inhibitors, weighting agents such as salts, pH adjusters, freeze suppressants, tracer materials for studying reservoir characteristics, and stimulation fluids. In addition, toxic contamination can occur from cuttings and fluids encountered during drilling such as from formation hydrocarbons. Reservoirs on the North Slope presently being developed range from 6,000 feet deep to over 10,000 feet. As drilling depths increase more demands are made of the drilling fluids, increasing the need for additives.

Industry has been looking at less toxic additives for use in the drilling operation. For instance, chrome mud was used freely in the drilling of Prudhoe Bay unit wells. Newer fields, such as the Kuparuk River unit, tend to use chrome free mud. Diesel based mud is being used less frequently as drilling technology improves and as subsurface geology is better understood. The department encourages the addition of less toxic additives and considers it to be an important adjunct to waste disposal. Less toxic wastes reduce the risk from disposal site failure.

One method for reducing waste volume being tried is separating out the non-toxic portion of the wastes. ARCO Alaska, Inc. has a pilot project in which they are separating cuttings that are brought up from the first 3500 feet of wells from the drilling mud. These cuttings account for approximately 50% of the cuttings volume total. The top hole drilling tend to be vertical and consists of thawing sands and gravel cemented together with permafrost. These cuttings are very similar to sand and gravel from local pit mines.

The sand and gravel, once separated, are then washed of residual mud. After testing to verify that washing is complete and that the cuttings are chemically similar to surface sands and gravel, the cuttings will be approved for use in construction. These recycled materials may end up in a road, a structural foundation, or in sand bags. The ease of separating sand and gravel particles from drilling mud and additives is an important aspect of this project.

The department requires plan review of the washing equipment and the sampling plan proposed for verifying leachate potential. As of this writing the sampling plan ARCO has proposed is to determine sample pH and total petroleum hydrocarbon concentrations, followed by acid digestion and analysis for arsenic, barium, cadmium, chromium, copper, iron, lead, manganese, mercury, nickel, selenium, silver, sodium, sulfates, and zinc. Samples are to be taken every 500 feet of drilling depth. Results are compared to analysis results for typical local surface gravel. Should the samples fail this test, ARCO is proposing a leachability test with the leachate being compared to the state's water quality standards. The department is looking forward to results of this pilot project.

Recycling the mud system is another method used to reduce waste volumes. As the mud surfaces, shakers and cyclones are used to remove cuttings, cleaning the mud for reuse. A typical well on the North Slope requires the use of two separate mud systems. The first is used through the permafrost zone. Once at the depth where horizontal deviation occurs, approximately 3,500 to 4,000 feet, the initial mud system is disposed and a second system introduced. Recycling the second system is done throughout drilling the remainder of the well, at which time it, too, is disposed. Recycling mud systems from well to well is not currently performed on the North Slope, though the department understands it is done in other states. We are interested in knowing more about and promoting well to well recycling.

Reducing the drilling hole volume reduces the waste volume generated. This is being done in a number of ways on the North Slope. New technology is improving the efficiency of drilling, requiring fewer holes to access more reservoir. For instance, if a bottom hole is unsuccessful in accessing a producing zone, the well can be recycled by deviating from the well bore to a new bottom hole location. Similarly, multiple bottom hole locations can be drilled from one well during exploration. Successful reworking of a well allows new sections of the well bore to be used for production of hydrocarbons. Improved reservoir stimulation practices allow oil recovery at greater distances from the well bore (2).

Recently, horizontal drilling has been used on the North Slope. Horizontal drilling, a refinement of directional drilling, allows the well bore to horizontally travel through the reservoir resulting in increased reservoir contact. It is limited to deeper reservoirs which allow enough room for the drill to angle into the oil horizon.

The department, as policy, encourages all methods that reduce waste volumes needing disposal; however, there are no mandatory State requirements for reduction of waste volumes. Economics play a major role in when and how waste reduction occurs.

Disposal of Drilling Waste by Injection

Subsurface injection of drilling wastes is an ongoing practice on the North Slope. Though this method of disposal has been questioned for use in the Lower 48, there are a number of reasons it is an accepted practice in our most northern part of the country. These reasons have to do with the availability of wells, the geology, and relative importance of resources.

Obviously, with the primary industry on the North Slope being oil and gas development, resources for drilling and maintaining wells are readily available. Though waste injection has not occurred at these depths, it shows the extent of known technology. Many injection wells are located at the oil well drilling sites, eliminating the need to transport wastes and subsequent spillage.

The North Slope is a 30 to 80 mile wide alluvial plain which stretches along Alaska's north coast. It is formed from silt, sand and gravel sediments that originated from the Brooks Range, the mountain range which forms the plain's southern border. Subsurface geology is uniform throughout the area, which partially accounts for the large oil and gas traps found. For instance, the Prudhoe Bay formation is approximately 30 by 50 miles. Also of importance is the continuous permafrost across the North Slope descending from near the surface to between 1000 and 2000 feet. In the Prudhoe Bay area the permafrost bottom is in the 2000 foot range. In addition to permafrost, horizons of siltstone and shales confine subsurface fluids (3). Large uniform formations and 2000 feet of permafrost and shales forming impermeable boundaries makes injection attractive on the North Slope.

It is worth noting that should oil and gas exploration be allowed in the Arctic National Wildlife Refuge, injection will be considered as a major method of waste management. However, the geology of this area has not been proven and may be significantly different from the Prudhoe Bay area. One known difference is that the permafrost only ranges to the 1000 foot depth in the refuge.

Subsurface injection is highly preferred by the department over surface discharges that can compromise surface water resources. The North Slope forms one of our nation's important wetland complexes, supporting rich biological resources (4). The surface resources also provide the only drinking water for North Slope human inhabitants, whether they be indigenous populations or industrialist migrants. Groundwater found below the permafrost mostly have total dissolved solids concentrations over 10,000 milligrams per liter, though some range from 3,000 to 10,000. In the early 1980s one company tried ground water as a drinking water source. The source was abandoned after two years due to the high costs of treatment and maintenance.

Two methods of injection are practiced on the North Slope: through the well tubing and through a well annulus. In general, wells that dispose through the tubing are deeper and inject a wider variety of wastes.

Wells which use tubing for injection are referred to as dedicated wells. Few of these wells on the North Slope have been drilled specifically for injection. Most are converted wells that have exhausted their original purpose. Dedicated wells typically inject between the 5000 and 6000 foot depths, but some are as shallow as 1900 feet. Dedicated wells dispose, in addition to drilling wastes, other field wastes such as production facility clean ups, workover and stimulation fluids, and produced fluids. Dedicated wells are regulated through the Underground Injection Control program and are classified as Class II wells. In the state of Alaska, the Alaska Oil and Gas Conservation Commission has primacy over Class II wells. One well has recently been permitted as a Class I nonhazardous well, and will likely be open for support industry use.

Annular injection occurs by injecting through the annulus between the surface casing and the casing immediately inside of it. The tubing can then be used for other purposes. The surface casing is typically set at between the 1900 and 3500 foot depth. Figure 1 is a schematic of what a well looks like and where

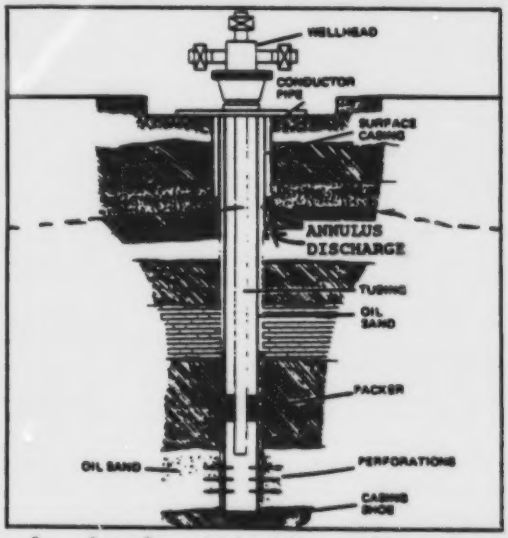

Fig. 1. Annular injection well schematic.

injection occurs. Annular injection consists primarily of disposing the liquid portion of drilling wastes from drilling a well itself, other wells and reserve pit fluids in the immediate vicinity. One well can be used for disposing all wastes at a production pad, which may have up to sixty wells. Annular injection is exempt from the Underground Injection Control Program and is regulated by the department. To simplify regulating these disposals, a general permit has been issued which stipulates what information, shown in Table 1, must be submitted to the department for authorization to inject. The general permit limits

disposal to fluids produced from the drilling, servicing, or testing of oil and gas exploration, development, service, and stratigraphic test wells to zones containing total dissolved solids of greater than 3000 milligrams per liter.

TABLE 1

Information Requirements To Apply For Annular Injection

1. Well designation or name, and description of the well with a map or plat of the well location.

2. A list of materials to be injected, description of the materials, estimated volumes of each material, and sources of all materials to be injected.

3. The total estimated volume of material to be disposed.

4*. A description of the zone that the wastewater will be entering including the top and bottom depths, the geological make-up above and below the zone, permeability of the zone, operating pressure of the zone, and salinity of the ambient water within the zone.

5. The depth at which injection will occur.

6. Beginning and ending dates the disposal will occur.

7. A schematic of the well and casing layout to a point 100 feet below the bottom of the injection zone.

8. The method to be used to seal the injection zone when disposal are finished.

9. Anticipated time by when the injection zone will be sealed.

* For wells where this information will not be available prior to disposal, as in an exploration well, the information is to be reported in the final report.

A recent development in injection on the North Slope is BP Exploration (Alaska) Inc.'s pilot project which uses a ball grinder to grind cutting solids to particle sizes that can be injectioned. This pilot project has proven successful enough that a full scale unit was installed beginning July 1, 1990. Injecting the solids, reduces surface discharges needed and the surface disturbances needed for those disposal. The department sees this as a major improvement.

Though injection is a preferred method of disposal by the department, there are some concerns. The integrity of well hardware is an important consideration. We depend on the Alaska Oil and Gas Conservation Commission to provide expertise and to enforce their well integrity program. Another concern is the migration

of wastes and surfacing through a well bore. There appears to be no, or minimal, flow in the aquifers below the permafrost (3). However, as early as 1975 industry has been concerned about thawing around well casings from warm fluids flowing through them (5). Thawed soils may provide a migration pathway for wastes. Because of low flows in aquifers and the presence of other confining zones the department feels the likelihood of this occurring to be low, but further data should be collected.

Below Grade Burial of Wastes

Having found that surface pits cause leaching problems even when covered, permafrost was looked at for improving containment. Permafrost was considered because of its ability to bind wastes in a stable cemented matrix. Further, permafrost burial could be accomplished by currently used construction methods.

Two types of below grade pit designs, shallow burial and deep burial, have been used to freeze wastes into permafrost, a practice referred to in Alaska as freeze back. Shallow burial pits are constructed by ripping frozen soils using tractor mounted rippers. The resulting pit is up to 60 feet deep and can encompass several acres to several hundred acres. Deep burial pits are constructed using a power auger to drill a hole up to 12 feet in diameter and 120 feet deep. A minimum 6 feet of undisturbed soil must be left between auger holes for soil stability.

An important part of a freeze back design is the thermal regime. Wastes placed in below grade reserve pits have been documented thawed for two years after closeout due to stored heat and latent heat of freezing. An excavated pit forms a bowl in the permafrost which can fill with the sheetflow of surface meltwaters. Actions to promote freezing include removing free liquids, cooling wastes prior to disposal, and closing pits in the fall providing a full winter for freezing. The deeper into permafrost the waste is buried, the colder and more static the surrounding soil temperatures. This is one reason why the deep auger hole burial is preferred for freeze back.

The freezing temperature of wastes in relation to surrounding soil temperatures is also important. Freeze back does not work unless the wastes freeze. Freeze depressants such as salts, hydrocarbons and alcohols complicate freeze back. Brine pockets caused by dissolved solids being concentrated as they are excluded during the freezing process are a common feature in natural permafrost found on the North Slope. Because many mud systems have high salinity concentrations, significantly sized brine pockets potentially could form. Other concerns are frost heaves and contraction cracks caused by soil contractions during cold weather (6).

The State's regulations require that in freeze back the surface level of all wastes at close-out be at least two feet below the active thaw zone. It is important to delineate the active thaw zone, which is defined as the surface layers of organic matter and mineral soils which thaw each year in areas of permafrost. As a rough estimate, the modified Berggren equation has been applied

to sites where below grade pits have been proposed (7). The Berggren Equation is typically expressed as follows (8):

$X = \lambda \times \text{sq rt of } (48\ k_s \times nI/L)$

Where:

X = depth of thaw

λ = coefficient which considers the effect of temperature changes within the soil mass

k_s = average thermal conductivity

I = air thawing index

n = an empirical constant relating air and surface thawing indexes

L = latent heat

Many of these variables, including the empirical factor, are not well established for North Slope sites and predicting specific thaw depths has proven difficult (7). Factors that can affect sites are wind exposure, sun exposure, distance to the ocean or Brooks Range, cover material used, soil moisture content, and susceptibility to snow drifting. Little is known how disturbing soils will affect their insulating capacity. Thaw depth vary from site to site, as well as within a site. For example, the south west corner of a site will have the greatest exposure to the sun and, because of prevailing winds, will have the greatest snow cover from drifting. Activities that change the thermal regime of a site so as to negatively affect freeze back are prohibited.

Only limited data exists for extreme climactic conditions on the North Slope due to the short history of collection. Except for the past 15 years, most historical data is from Pt. Barrow, over two hundred miles from Prudhoe Bay. Long-term climatic trends must also be considered in determining thaw depths. Long-term trends are difficult to predict, though there is much debate currently surrounding such concepts as the global greenhouse effect.

To verify thaw depths, thermistors are now required in all closed-out reserve pits using freeze back. Thermistors are capable of measuring temperatures based on electrical conductivity changes as temperature changes. They have provided reliable results without disturbing a site. Thermistors can be removed, tested and replaced without affecting the site. Good design requires attention to conductive and convective heat transfer through the well casing. Thermistors are placed in the pit center, and other locations where variability in the thermal regime can be expected, such as areas of snow drifting or surface waters. Maximum thaw occurs during late September into October, which is a critical time for monitoring.

As the department learns more about permafrost, concerns about fluid migration through upper frozen layers have increased. Migration can occur through the formation of lakes, meandering of creeks and rivers, and fluid movement through permafrost cracks. These are long-term problems that may not manifest for years, long after an operator has discontinued monitoring and has abandoned a site.

Lakes can form due to altering the thermal regime. Heat input will increase by removing the insulating organic soils or having shallow water. The increased heat input will thaw into the permafrost, thawing ice rich soils. Subsequent collapse of the soils, known as thermokarsting, creates a lake which further increases heat input. This process repeats until thermal equilibrium is reached. What starts as a small depression may grow to a lake that will influence the integrity of a site.

Many creeks and rivers on the North Slope have cut banks which are tens of feet below the surrounding tundra. Most North Slope soils lose structural stability once thawed. As a river bank erodes through thawing, the river undergoes lateral migration. Though mostly low energy systems, aerial photographs show evidence of the thaw induced meandering of rivers. An example of this is near the Oxbow Landfill operated by the North Slope Borough, which has been the recipient of drilling wastes in the past. One hundred feet from this landfill is the Putuligayuk River. During the spring thaw of 1989, high runoff caused six foot wide sections of river bank to erode. Similarly, thermal erosion occurring along the ocean coast moves the coast inland at an average rate of a foot a year. This thawing is important in the siting of disposal sites.

Below surface ice lenses and ice wedges form when a portion of water migrating through cracks in the permafrost freezes. Figure 2 is a diagram of the formation of an ice wedge. The top 20 feet of the soils on the North Slope often have massive concentrations of ice wedges and lenses. The typical soil boring in Figure 3 demonstrates this. The water that migrates through permafrost cracks has the potential of leaching contaminants from a site. We have had experiences where diesel has been found to migrate laterally through cracks in the permafrost hundreds of feet. This phenomenon is poorly understood at this time and needs to be better understood if more shallow depth pits are to be constructed. Deep auger holes have the advantage of being able to be below these surface phenomena.

An important part of pit maintenance is a fluid management program to prevent the pit from leaking or overtopping. Fluid management is an ongoing concern, as each winter, drifting snow will fill a pit. Presently, the main method of fluid management is injection as described earlier. Removal of uncontaminated snow prior to thaw is also widely practiced. In the past, discharges of fluids directly to tundra or to road surfaces were allowed. These practices have been discontinued because of difficulties with monitoring and of controlling water quality. Frequent violations of the water quality standards were recorded. To avoid fluid management requirements, some pits have been designed to be closed out after one season of use. This has been accomplished by utilizing cellular development or the auger holes. The difficulty with one season pits has been predicting the volume of one season's waste production.

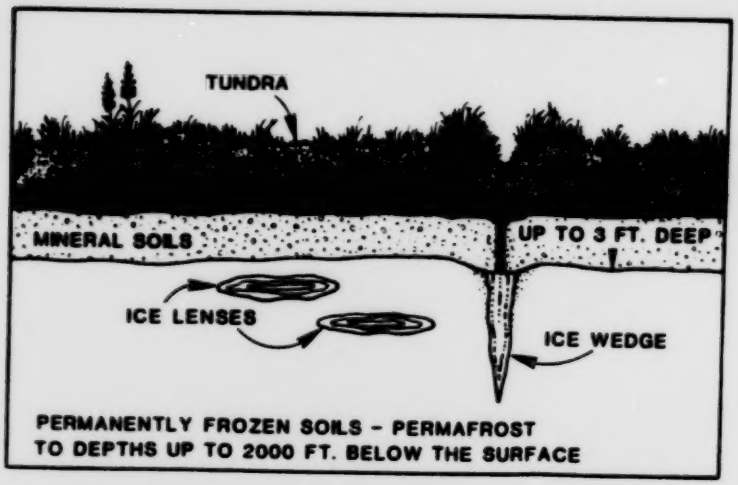

Fig. 2. Fluid migration and ice formation of near surface soils.

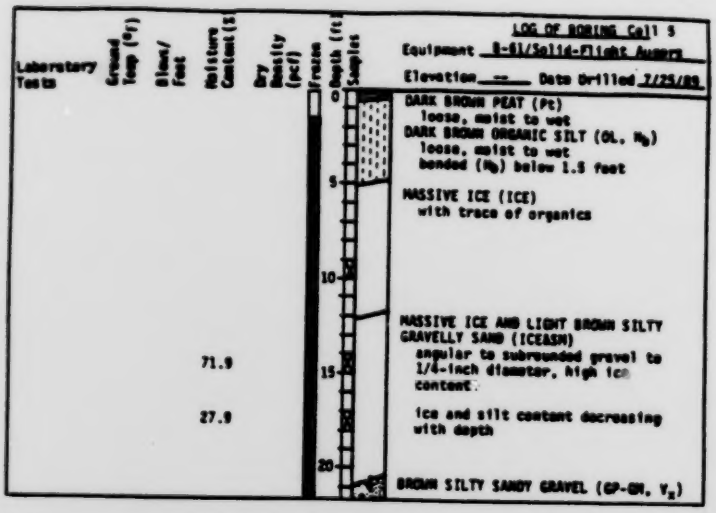

Fig. 3. Frequently encountered boring log from North Slope.

Monitoring of Reserve Pits

Once a pit is designed, constructed and closed-out, monitoring becomes the frontline in determining whether the facility is performing to standards. The regulations requires a minimum five years of monitoring after close-out of a site. Because long-term stability of below grade reserve pits is not known, we

will be monitoring some sites for years longer. In general, present reserve pit operators are required to do site visits, aerial photography, and surface water monitoring. In addition, samples of the waste are taken and the crystallization point of the waste determined for comparison to ambient soil temperatures.

Visual inspections are conducted at least once per year during late summer. During these visits the site is inspected for any degradation or damage to the cap or facility from erosion, cracking, freeze-thaw cycles, frost heaves, burrowing animals, changes to the thermal regime, any ponding surface waters on or adjacent to the cap, any seepage from the disposal site or any surface water discoloration, any damage to vegetation adjacent to the site, any damage to monitoring devices, any damage to survey monuments at the site, the status of revegetation of the disposal site cap, and any other events of note. Besides visual observations, thaw probing by driving a rod into the ground until refusal is required during the period of anticipated maximum thaw.

Aerial photos of each site are required during late summer of each monitoring year. Photographs are not required to be taken for scaling, so they can be taken out the side window of a helicopter or plane during a fly-by. The photographs must clearly show the disposal cell and surrounding area for approximately 300 feet. These photographs are required during each year of operation, at close-out, as well as during the post-closure monitoring period.

Water quality monitoring consists of taking samples at two sites downgradient and one upgradient of the facility, and field testing around the pit perimeter. Typical analysis for the samples is pH, conductivity, salinity, chromium, cadmium, barium, lead, sodium, zinc, potassium, aluminum, arsenic, and chlorides. Field testing consists of monitoring for pH and salinity every 50 feet of the perimeter of the site where surface water is found.

Consolidation of Sites

The state is developing a policy that will require that surface disposal sites be limited through consolidation. Most North Slope oil and gas development to this point has been on state lands. Consolidation is meant to reduce liability the state may incur should the long-term integrity of sites not perform as expected. Besides reducing the number of sites where liability is incurred, consolidation reduces long-term monitoring costs, and consolidates drilling waste handling facilities. Consolidation allows more resources for site investigation and equipment development fewer will be needed.

Concluding Comments

During the early 1980s, drilling wastes were being managed in surface impoundments which contributed to the release of the wastes to surrounding environments. During the past five years a series of management alternatives have been tried. These alternatives include waste reduction, injection, deep hole freeze back, shallow hole freeze back, and treatment and subsequent use of the treated waste as construction material. All these methods have shown promise

in helping to reduce or eliminate contamination from drilling wastes. The department's preference in descending order is waste reduction with no discharges, injection below the permafrost, treatment to remove inert constituents and the product used as construction material, burial deep into the permafrost where the frozen matrix is the most stable and shallow burial in the permafrost. Treatment to remove inert constituents is limited to those situations where the treatment can be conclusively verified, which would limit its use.

The North Slope is known for its wetlands which have international significance. Protection of these resources is a department priority. Any future policy that is developed will likely emphasize the discontinuance of surface discharges, and to promote the elimination of reserve pits. These goals appear to be attainable based on the success of pilot projects that have been tried, though further research will be needed to refine these waste management methods.

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E&P WASTE MANAGEMENT IN THE COMPLEX CALIFORNIA REGULATORY ENVIRONMENT -- AN OIL AND GAS INDUSTRY PERSPECTIVE

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INTRODUCTION

The California regulatory environment presents unique challenges for waste management operations in the oil and gas exploration and production (E&P) industry. Major production facilities are located in environments that vary widely from desert areas and fragile coastal dunes, to the densely urbanized Los Angeles Basin. Waste management operations in these areas must be carried out in a manner that is both environmentally sensitive and cost effective. Operators must comply with the requirements of the complex California regulatory framework which is separate from, and typically more stringent than, the federal waste management framework (RCRA). Additionally, California regulations do not include any exemption for E&P waste comparable to that found under RCRA.

Industry is meeting this regulatory challenge through continued development of comprehensive waste management programs staffed by career environmental professionals. Environmentally sound approaches to beneficially reusing and recycling waste streams have been developed to reduce the volume of material that must be disposed. Programs to reduce waste toxicity have been implemented. Additionally, comprehensive audit and training programs are being conducted to ensure that waste is being managed effectively and in compliance with applicable regulations. Industry, working though the Western States Petroleum Association (WSPA), has also been proactive in the development of waste management regulations that are workable and protective of human health and the environment. Emerging issues for E&P operations include new requirements for the management of wastes that contain organics (mandated pretreatment prior to land disposal and imposition of emerging

organic toxicity characteristic standards); risk-based soil clean-up levels; and imposition of corrective action programs at E&P facilities.

INDUSTRY OVERVIEW

California is a major oil and gas producing state, ranking fourth nationally in oil production. In 1988, California's 44,000 oil and gas wells produced 387 million barrels of oil and 2.8 billion barrels of water. Thermally enhanced production (both cyclic and steam flood) accounted for 186 million barrels of this total oil production and waterflooding accounted for 57 million barrels. These enhanced oil recovery (EOR) projects injected a total of 1.8 billion barrels of water.[1]

Total annual waste volumes from E&P operations are estimated to be approximately one billion barrels of produced water (excluding produced waters beneficially reused in EOR); 700,000 tons of tank bottoms and other associated wastes (including scrubber fluids and and water softener regeneration brine); and 300,000 tons of drilling muds.[2]

The magnitude of these waste streams gives some indication of the management challenge facing both industry and state regulatory agencies. An overview of the principal agencies which regulate waste management operations and the overall regulatory framework follows.

REGULATORY FRAMEWORK

The regulatory framework governing waste management in California presents something of a paradox. The regulations, which are administered by a number of independent agencies, are complex and lack an exemption analogous to the federal RCRA provision that exempts E&P waste from being classified as hazardous waste.[3] The regulations for California-only hazardous waste do not, however, incorporate the rigid "listing" approach that is found in the RCRA regulations. The regulatory framework therefore is flexible enough in most cases to allow operators to manage waste streams in a manner that reflects site-specific considerations.

Four agencies oversee the majority of the requirements governing waste management: the Department of Health Services, the State Water Resources Control Board and associated Regional Water Quality Control Boards, the Division of Oil and Gas, and the California Integrated Waste Management Board. The relationship between each of these agencies with respect to management of E&P waste is depicted in Fig. 1. While the four agencies have overlapping jurisdiction for E&P waste management, memoranda of understanding among the agencies reduce duplicative regulation.[4] (The "sieves" in Fig. 1 define each agencies operational involvement in various E&P waste streams.)

Specifics regarding each agency's role in E&P waste management follow.

Department of Health Services (DHS)

The primary role of the DHS is the administration of the state hazardous waste program. Waste is defined statutorily as hazardous if, "because of its quantity, concentration, or physical, chemical, or infectious characteristics [it] may either: A) Cause or significantly contribute to an increase in mortality or serious...illness. B) Pose a substantial...hazard to human health or environment when improperly...managed."[5] The DHS has also promulgated regulatory criteria used to classify waste as hazardous or non-hazardous.[6] Due to the lack of a California E&P exemption, some E&P wastes are hazardous under these regulatory criteria.

At present, the DHS does not have authorization to manage the RCRA program in California; accordingly operators must comply with both state and federal regulations. The DHS is currently working to develop an integrated regulatory framework and will likely obtain authorization to manage the RCRA program within the next year. The oil industry, through WSPA, has been heavily involved in this massive regulatory development effort (discussed in subsequent section).

As noted above, there are no "listed" wastes in California analogous to RCRA listed wastes. The regulations do, however, include lists of waste that may be hazardous. These lists include drilling mud and tank bottoms.[7] California has developed detailed scientific criteria for determining if a waste is hazardous.[8] Operators must determine that a waste is hazardous or nonhazardous based on laboratory testing or knowledge of the waste stream.[9] Laboratory analysis includes testing for toxicity, ignitability, reactivity and corrosivity. Toxicity testing includes testing for aquatic toxicity (96 hour LC50 < 500 mg/L) and testing for specified organic and inorganic chemicals. The heavy metals test is performed at pH 5.0 with digestion in citric acid (except for chromium VI which is done in deionized water). Table 1 provides the heavy metal limits for hazardous waste classification.

State Water Resources Control Board (SWRCB)

The SWRCB is primarily responsible for the protection of the state's water resources (including groundwater), and preservation of beneficial uses of those waters. The state program is implemented by nine semi-autonomous Regional Water Quality Control Boards (RWQCB). In the waste area, the RWQCBs are responsible for regulating and permitting discharges to land (at classified and unclassified waste management units or land disposal facilities) and to water.[10] RWQCBs also administer the federal NPDES program and the state underground injection program (except Class II wells). The RWQCBs also develop "Basin Plans" for the maintenance and improvement of surface and ground water quality.[11] All discharges within a basin which may impact waters of the state are required to be consistent with the Plan's goals.

The SWRCB maintains a waste classification framework which is related to the DHS scheme and primarily focuses on nonhazardous waste. Nonhazardous waste

is further delineated as "designated", "non-hazardous solid", or "inert". Designated waste, which may include drilling muds and tank bottoms under certain conditions, has separate management requirements from solid and inert waste.

The SWRCB has adopted a policy identifying "sources of drinking water" which specifies that, with limited exceptions, all waters of the state are considered to be sources of municipal or domestic drinking water (existing or potential).[12] The policy provides exemptions for some waters which, because of existing contamination, quantity, or other considerations make them unsuitable as drinking water sources. Aquifers which are exempt under the underground injection control program are not sources of drinking water. Groundwaters containing 3000 ppm or greater total dissolved solids can be exempted based on beneficial use designations.

A related regulatory framework for the protection of drinking water is Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986.[13] Although the Health and Welfare Agency is primarily responsible for implementing Proposition 65, key terms are defined in SWRCB plans and policies. Passed by the voters as a popular ballot initiative, the law prohibits the discharge of chemicals into water or onto land when that the chemical will pass or probably will pass into any source of drinking water and pose a "significant risk" of causing cancer or reproductive toxicity. Over 200 chemicals, including benzene, have been identified by the state. The law potentially impacts E&P operations in several ways, including pit construction and operation, and produced water disposal. Assuring compliance has been a concern to industry because of the ambiguity of the law.

Department of Conservation -- Division of Oil and Gas (DOG)

Charged with responsibility for management and conservation of the state's oil, gas and geothermal resources, the DOG permits new oil, gas and geothermal wells, mechanical modifications to existing wells, and well abandonments.[14] The DOG has primacy from the EPA under the Safe Drinking Water Act to administer the underground injection control (UIC) program for Class II wells.[15] The DOG program has received high marks from the EPA for environmental (groundwater) protection.

The DOG also has environmental oversight responsibilities for all surface production facilities (including well locations, sumps, and above ground tanks); oilfield waste/refuse management; and site restoration.[16] Additionally, the DOG requires oil spill contingency plans for all tank settings where releases might impact public health or the environment.

California Integrated Waste Management Board (WMB)

The WMB regulates landfill disposal of nonhazardous industrial waste and municipal solid waste.[17] County agencies typically serve as the local enforcement agency for E&P waste, granting permits for waste disposal sites.

The WMB jurisdiction overlaps with that of the SWRCB, although the focus of the two regulatory programs differs.

INDUSTRY WASTE MANAGEMENT PRACTICES

Waste management practices are dictated by the geographic setting of the facilities and the applicable state, regional, and local regulations. Typical industry practices are outlined below for the major E&P waste streams.

Produced Water

Produced water is by far the largest waste volume generated in California oil and gas production. Of the approximately 2.8 billion barrels produced in 1988, over 60% was utilized in secondary and thermally enhanced oil recovery projects. This use of produced water also results in ancillary waste generation (through filtering, treating and softening), which are discussed later.

In addition to the produced water injected in enhanced recovery projects, 678 million barrels were injected in 1988 for disposal in Class II injection wells. The remaining volume of produced water was disposed to publicly owned treatment works (POTWs); discharged to the ocean; used for agricultural or industrial purposes; or disposed in evaporation and percolation ponds (in areas where no groundwater exists or where beneficial uses of groundwater would not be impaired).

The EOR injection programs and injection for disposal are regulated by the Division of Oil and Gas consistent with the federal Class II UIC program. All surface discharges of produced water are regulated by both the DOG and the RWQCBs. RWQCBs have primary regulatory authority over surface discharges and issue the required waste discharge permits. Discharges to POTWs are managed by permits between the dischargers and the receiving sewer systems. These permits typically specify stringent discharge limits for produced water constituents (e.g., oil and grease, ammonia, dissolved H_2S).

Drilling Muds and Cuttings

The disposal of muds and cuttings is regulated by the four agencies discussed above and depicted in Fig. 1.

In areas where there are groundwater concerns, mud pits must be lined or tanks must be used to manage mud systems onsite. Where there are no groundwater concerns, state regulations permit the discharge of nonhazardous muds and cuttings to onsite sumps provided all the wastes are removed from the sump prior to closure, or all free liquids are removed and the sump is promptly closed. The practice of burying solids is only permitted in areas where beneficial uses of groundwater will not be impaired. Since only

nonhazardous muds and cuttings may be disposed onsite, operators are required to verify that materials left in the pit are indeed nonhazardous.

It is important to ensure from an operational point of view that no extraneous materials enter the mud pits (such as pipe dope cans, waste lubricating oils, mud sacks, solvents, or excess treating chemicals). The presence of extraneous materials could result in the entire contents of the pit being considered hazardous.

In fields where onsite disposal is not permitted, such as in urban and agricultural areas, the muds and cuttings must be disposed in permitted disposal facilities. Operators are now using solids removal equipment (belt and filter presses, centrifuges, etc.) to separate solids and liquids at some sites. The liquids are injected in Class II wells and the solids disposed of in permitted facilities. This practice significantly reduces the total volume of waste that must be transported to offsite disposal facilities.

Some operators also utilize company-owned, permitted land treatment facilities to manage their muds and cuttings. In this process, the liquids are allowed to evaporate, the metals are adsorbed onto clay particles and organic materials biodegrade. Solidification and immobilization processes have also been utilized to treat muds and cuttings, chemically fixing metal and organic constituents. Nonhazardous muds and cuttings treated in this manner are being beneficially reused for daily municipal landfill cover.

Industry has worked cooperatively with the DHS to develop an approved list of drilling mud additives which, when used in concentrations typically found in drilling operations, will not cause the muds and cuttings to fail the DHS's hazardous waste testing criteria. If additives other than the those listed are used, the muds and cuttings must be tested to ensure they are nonhazardous. The approved additives list is published in the API Environmental Guidance Document.[18]

Muds and cuttings which fail the hazardous waste test are disposed of in permitted hazardous waste disposal facilities. General industry experience is that very few muds fail the DHS characteristic tests.

Well Workover and Completion Fluids

Spent workover and completion fluids include weighting agents, surfactants, acids, inhibitors, and gels.

These fluids are regulated in the same manner as muds and cuttings. The fluids are typically produced through the flowlines to production facilities and injected into Class II wells. The nonhazardous solids that are separated from the fluids can be buried onsite in areas where the practice has been approved by the RWQCB. In areas where onsite disposal is not permitted, management alternatives include disposal in approved sites or treatment to solidify/immobilize constituents.

If the wastes are hazardous and are to be shipped offsite for disposal, tanks are used to contain the fluids and solids. Offsite disposal of any hazardous fluids or solids must be to permitted hazardous waste disposal facilities.

Tank Bottoms and Other Crude Contaminated Solids

The management of crude oil contaminated solids (tank and vessel bottoms, oil contaminated soils, sump bottoms, etc.) is primarily dictated by whether or not the material is hazardous. Recent experience indicates that over two-thirds of these wastes are nonhazardous. The wastes that do fail the hazardous waste tests do so primarily because of ignitability; the remainder fail due to heavy metal contamination (usually lead, arsenic, vanadium, or nickel), or reactivity (release of hydrogen sulfide).

Nonhazardous oil contaminated solids must be managed in a way which will protect the environment. Operators are in some cases processing these materials to recover oil, utilizing solvent (condensate) treatment methods and mechanical separation equipment (filter and belt presses and high speed centrifuges). The remaining solids are either land disposed (including land farming) or utilized onsite as road base or berm material. Some operators have installed equipment to beneficially use the solids to make road paving material similar to commercially available products.

Substantial volumes of oily soils are being generated in E&P site clean-ups as regulatory agencies impose clean-up standards which are increasingly stringent. Mandated clean-up levels vary from 0-10,000 ppm total petroleum hydrocarbons, based on land use, hydrogeology, and the policy of the local enforcement agencies. Agencies have in some cases specified clean-up levels which go far beyond what is required to protect the environment and without considering natural biodegradation processes. WSPA is supporting a DHS initiative to implement a risk-based approach to clean-up based on site-specific considerations.

California is in the process of promulgating regulations which will prohibit the disposal of hazardous petroleum waste without pretreatment for removal of organic constituents. These regulations, which are part of the California land disposal restrictions program, are analogous to the federal land ban for third-third RCRA waste (i.e., treatment to remove hazardous characteristics).[19] Complex waste treatment facilities (e.g., solvent extraction units for removing petroleum from waste) will have to be constructed at sites where significant volumes of hazardous oily waste are generated.

Other Associated Wastes

Thermally enhanced oil recovery projects generate several waste streams. The highest volume streams are water softener regenerate brine, water filter backwash and filter media, and SO_2 scrubber liquor. The DOG, with concurrence from the EPA, has approved these fluids for injection in Class

II wells. The fluids are either commingled with produced water for injection or injected in dedicated wells. In some cases, SO_2 scrubber liquor is beneficially reused as an oxygen scavenger since it contains high concentrations of sodium bisulfite. Filter media is managed as nonhazardous solid waste and disposed in approved industrial waste disposal sites.

The treatment of produced water to meet permit limits for discharge to surface waters or POTWs also results in the generation of wastes. Depending on the permit limit for oil and grease discharge, the water may be processed in gas or air flotation units in addition to primary separation units. The flocculated materials resulting from this process may be reprocessed to recover additional oil or managed as oil contaminated solids. Soluble oil is also occasionally a discharge problem. In one case, an operator is processing produced water through carbon filters to meet discharge limits. The spent carbon is sent to a recycler for regeneration and reuse.

Sweet gas production frequently must be treated to remove water vapor. Dehydration is usually accomplished by using either liquid desiccants such as glycol or solid desiccants such as alumina or silica gels, or molecular sieves. Spent glycol must be managed as a hazardous waste, and can be sent to a recycler for regeneration and reuse. The solid desiccants are managed as nonhazardous solid wastes as they do not fail the hazardous waste characteristic tests.

Industrial Wastes

Thermally enhanced oil recovery projects also generate several unique waste streams. The refractory bricks which line generator fire boxes are periodically replaced. These bricks have had a mixed history of being hazardous and nonhazardous waste. In general, bricks from gas-fired generators are nonhazardous, while those from oil-fired generators are often found to be hazardous due to heavy metals such as lead, nickel, and vanadium. Periodically, the internal sections of steam generators are washed to remove buildup of soot and other materials. The wastewater resulting from this practice often contains concentrations of heavy metals which causes it to be hazardous. Some operators treat these fluids to concentrate the heavy metals and send the concentrate either to permitted recyclers or hazardous waste disposal facilities.

Chemical drums have historically been a major waste management issue in the oil fields. Since California treats empty chemical containers differently than the EPA, the empty drums that contained hazardous materials are in some cases considered hazardous wastes. Most operators now have drum management programs in place to minimize the number of drums used in the oil fields through use of bulk chemical tanks (which are refilled when empty). Drums of chemicals are accepted only from suppliers who will take back the empty drums.

Nonhazardous waste lubricating oils from compressors, turbines, pumps and other moving equipment are typically recycled by mixing them with crude oil

streams for transportation to refineries. Under current law, motor vehicle engine oil and certain non-halogenated solvents are considered hazardous and must be sent to an offsite recycler or sent to a refinery which is owned by the generator.[20] Industry, working through WSPA, is assisting the DHS in sponsoring legislation which will allow the environmentally sound recycling of lease-generated used engine oils and non-halogenated solvents in any refinery (not solely the generator's).

Spent halogenated solvents present a special waste management challenge. Onsite recycling in the crude stream is not allowed under the regulations.[21] Additionally, few offsite recyclers will accept halogenated solvents. Therefore, operators have made it standard practice to avoid use of these solvents. When used, they must be segregated from other recyclable oils and solvents. Disposal is by offsite recycling at a permitted recycler or incineration.

INDUSTRY INVOLVEMENT IN THE REGULATORY DEVELOPMENT PROCESS

Industry and regulators are often characterized as being at odds, each having completely opposing goals in the regulatory development process. Our experience indicates that when industry and regulators communicate their objectives and constraints, more effective regulations can often be developed.

The oil industry has committed considerable resources to providing technical input to the agencies and legislature to assist in their development of effective, environmentally sound regulations. WSPA's Waste Management Committee has been an active participant in the various citizen's advisory boards established by the agencies to provide input to the regulatory development process. Two recent efforts are discussed below.

Development of an effective yet practical waste minimization program has been the goal of an extensive industry effort over the past two years. WSPA worked extensively with legislative staff on an approach that is feasible from industry's perspective and meets regulatory objectives. WSPA supported the waste minimization bill that was ultimately passed in 1988, and is currently working with the regulatory agencies to develop implementing regulations. The law requires the development of facility waste minimization plans and periodic performance assessments to review and oversee industry's progress in minimizing waste. It provides flexibility for operators to develop their own plans to meet waste minimization objectives, considering facility economics and other factors. Numerical goals are not mandated, making implementation of the law much more effective in extractive industries like E&P, and more workable than the current waste minimization proposals being considered in Congress.

For the last two years WSPA has also been actively involved with DHS efforts to recodify the California hazardous waste regulations and integrate the RCRA program into the state regulatory framework to obtain RCRA

authorization from the EPA. This massive regulatory package (over 3000 pages with several major re-writes and re-proposals) has required a significant commitment of WSPA resources to provide substantive input to the agency. The process has yielded a set of regulations that are more workable from both the agency's and industry's perspective.

A key industry issue in both of these efforts has been the development of regulations which industry can comply with on a consistent basis. Our experience is that regulators often do not fully appreciate the importance of strict compliance to corporations, or the difficulties and frustrations that can arise when corporate compliance staffs are forced to implement regulations that are not based on good science.

Industry's ability to maintain strong compliance programs is also being threatened by the deluge of waste management statutes that have been passed by the legislature in recent years. Regulatory agencies, as well as industry, are scrambling to keep up with these new statutory requirements. The statutes are often unnecessarily detailed, and sometimes contradictory with existing law or regulations.

Several major emerging issues will require a commitment by government and industry to work together if sound regulatory policy is to be developed. A significant issue for industry is the possible application of the federal organic toxicity characteristic to California E&P wastes. The impact of such an action would be particularly acute with respect to the management of produced water which is currently regulated by the DOG in an environmentally sound and effective program. Addition of this hazardous waste criterion to the current regulatory picture would detract significantly from the flexible, yet environmentally protective, regulatory framework that currently exists, and from the ability of the California oil and gas industry to be competitive with operations in other states.

Another major issue for industry is a recent move by the agencies to formally bring E&P facilities into the corrective action program. Agency proposals may require facilities which employ specified onsite hazardous waste treatment processes (e.g., elementary neutralization, wastewater treatment, drum rinsing) to conduct environmental investigations to determine if hazardous constituents have been released anywhere on the lease. Where releases have occurred, clean-ups will be required. Industry is advocating a program whereby corrective action would only be undertaken for significant releases.

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TABLE I - CALIFORNIA ASSESSMENT MANUAL - HEAVY METAL LIMITS

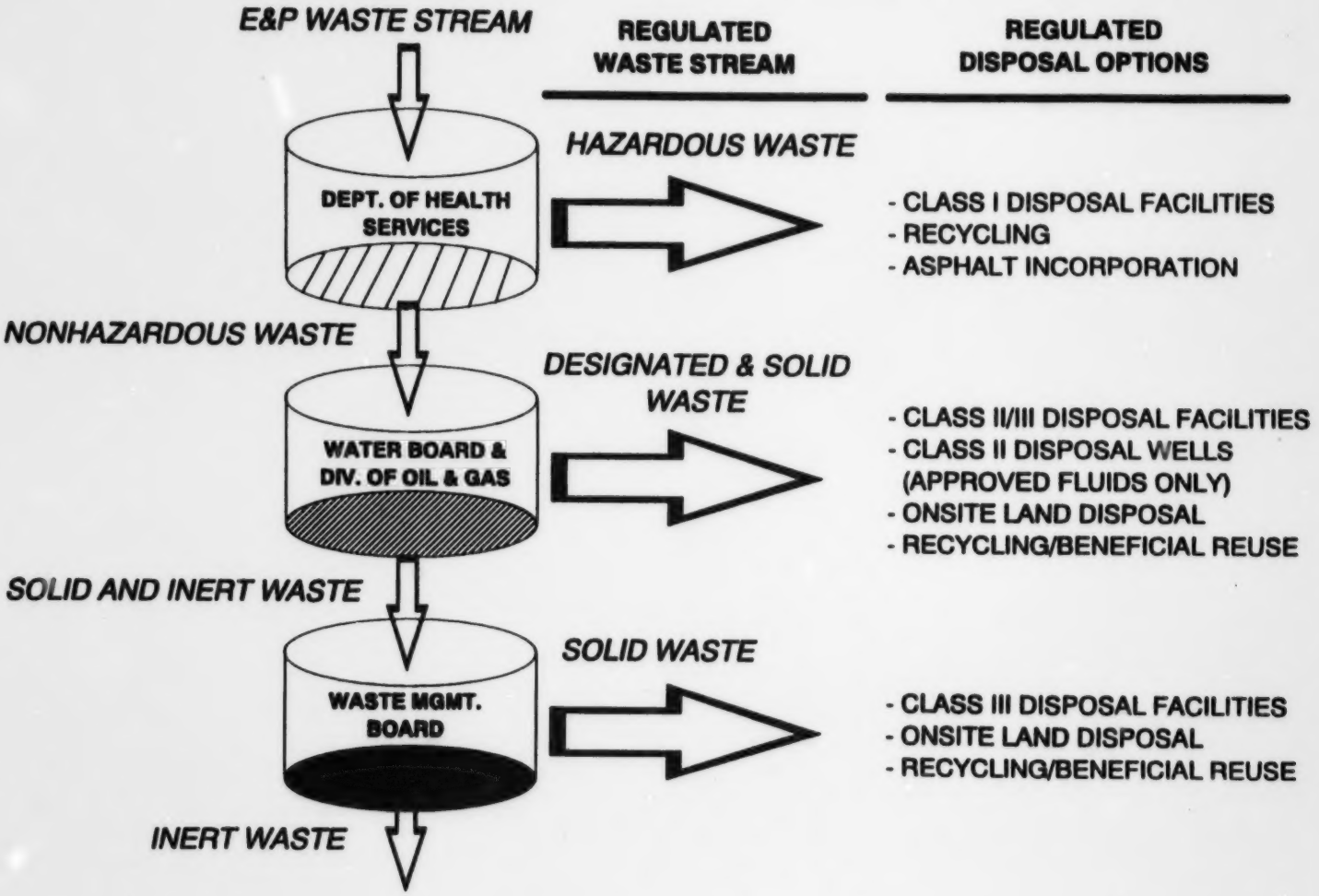
SUBSTANCE	TTLC* (mg/kg)	STLC** (mg/1)
Antimony (Sb)	500	15
Arsenic (As)	500	5.0
Barium (Ba)	10000	100
Beryllium (Be)	75	0.75
Cadmium (Cd)	100	1.0
Chromium (VI)	500	5.0
Chromium (Cr)	2500	560
Chromium (III)		
Cobalt (Co)	8000	80
Copper (Cu)	2500	25
Fluoride (F)	18000	180
Lead (Pb)	1000	5.0
Mercury (Hg)	20	0.2
Molybdenum (Mo)	3500	350
Nickel (Ni)	2000	20
Selenium (Se)	100	1.0
Silver (Ag)	500	5.0
Thallium (Ti)	700	7.0
Vanadium (V)	2400	24
Zinc (Zn)	5000	250

*TTLC - Total Threshold Limit Concentration: If the total sample concentration exceeds this level, the material is hazardous.

**STLC - Soluble Threshold Limit Concentration: If the Waste Extraction Test (WET) concentration exceeds this value, the material is hazardous.

FIGURE 1

E&P WASTE MANAGEMENT REGULATORY FRAMEWORK



AN EPA PERSPECTIVE ON CURRENT RCRA ENFORCEMENT TRENDS AND THEIR APPLICATION TO OIL AND GAS PRODUCTION WASTES

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Introduction

The purpose of this paper is to present an introduction and overview of the RCRA enforcement program, both generally and specifically as it applies to the management and disposal of oil and gas exploration and production (E&P) wastes.

Most E&P wastes are non hazardous solids, liquids or dissolved gases that are covered by RCRA regulations. The Resource Conservation and Recovery Act (RCRA) is the statute on which the RCRA Enforcement Division of the Office of Waste Programs Enforcement operates, under the Office of Solid Waste and Emergency Response (OSWER).

We will discuss three main areas:

I. A general overview of the universe of E&P wastes,
II. A review of the existing RCRA Subtitle C hazardous waste enforcement program, and
III. A discussion of how the E&P wastes are impacted by the existing Subtitle C enforcement program and the emerging Subtitle D solid waste enforcement program.

I. The Universe of E&P Wastes

By any measure, the U.S. oil and gas producing industry is big. It produces roughly eight million barrels of crude oil daily, and 44 billion standard cubic feet of natural gas. This production comes from roughly 800,000 wells at over 70,000 sites. (There are many more inactive and abandoned wells.)

The biggest volume waste is salt water, produced concomitantly with crude oil, at roughly 21 billion barrels annually. Most of

this is reinjected into the oil-bearing sands to stimulate more crude oil production. The next largest volume waste is about 361 million barrels annually of drilling fluids that comes from drilling about 70,000 new wells, or reworking old ones.

There are many smaller volume wastes that have been divided into exempt and non-exempt groups in an EPA Regulatory Determination dated June 29, 1988. Most E&P wastes are non-hazardous, as mentioned above, and therefore would be regulated as Subtitle D solid wastes under RCRA and the oil states' regulations. Also, the EPA Office of Water regulates and enforces two closely-related programs important to E&P wastes. They are the National Pollutant Discharge Elimination System (NPDES), and the Underground Injection Control program for disposing of salt water.

The NPDES program regulates waste water from oil and gas production discharged to navigable waterways of the United States through a discharged permit system. The UIC program regulates disposal of salt water from oil and gas production, enhanced oil recovery wells, and wells used for the underground storage of crude oil, liquified petroleum gas (LPG), and other liquid hydrocarbon products by establishing a system to control the permitting, construction, operation, and closure of injection wells.

The exempt group specified by the Regulatory Determination mentioned above is primarily high-volume low-toxicity waste that is clearly Subtitle D by today's definitions. The non-exempt group wastes are potentially all Subtitle C until testing proves otherwise. There are at this time 26 exempt wastes and 21 non-exempt wastes. Table 1 attached gives the wastes in each category.

II. Review of Existing Subtitle C Hazardous Waste Enforcement Program

RCRA enforcement has to date largely focussed on Subtitle C hazardous wastes. Subtitle D solid wastes are evolving into a larger part of the overall enforcement picture. RCRA is a complex statute covering many different types of wastes including:

- Hazardous waste under Subtitle C
- Solid Wastes (non-hazardous and special wastes) under Subtitle D
- Underground storage tanks under Subtitle I
- Medical waste under Subtitle J

Each of these Subtitles establish a different Federal/State relationship and a different enforcement scheme. Only Subtitles C and D will be discussed here. Figure 1 shows how the volume of E&P wastes compare with others in the Subtitle D universe. Under Subtitle D where most of the E&P waste is currently regulated, states have by far the largest enforcement role with only a very limited Federal authority.*

EPA's Subtitle C enforcement program includes the following components: monitoring compliance at facilities and taking enforcement action against violations. The next two paragraphs briefly describe this process.

Compliance Monitoring

Section 3007 of RCRA gives EPA, an authorized state, or a representative of either authority to conduct inspections, including examining facility records and obtaining samples. The two primary methods by which EPA or the states monitor compliance at RCRA facilities is by inspections or reviewing reports submitted by the facilities. The frequency of these inspections varies depending on the type of the facility.

Enforcement Actions

The primary goal of enforcement actions is to bring facilities into compliance and force the facilities to stay in compliance.

* Federal enforcement authority occurs only when the EPA Administrator determines that a state has not adopted a program adequate to address solid waste management facilities that may receive household hazardous waste or hazardous waste from small quantity generators.

There are a number of enforcement options available under RCRA Subtitle C. These include:

- o Informal actions such as written notices
- o Administrative actions such as an order or hearing
- o Civil actions filed in court
- o Criminal actions against firms or individuals

The complex relationship between EPA compliance monitoring and the civil enforcement process for RCRA is shown in Figure 2. This begins with an inspection report of violation(s). A decision to take enforcement action is made in which the state involved may take the lead. In these cases, the state procedures would be followed. An increased emphasis within RCRA is being placed on civil penalties as an effective enforcement tool. In general, penalties are rising for cases involving Subtitle C wastes. Although not uniform among the oil states, there has been a general tightening of enforcement in the disposal of E&P wastes in recent years.

III. Impact of Existing Subtitle C Program and Evolving Subtitle D Program on E&P Wastes

Impact of Subtitle C

As discussed previously, some E&P wastes are non-exempt under the Subtitle C program. In other words, E&P wastes that are listed as non-exempt are potentially Subtitle C hazardous wastes. A few examples of these are:

- o painting wastes
- o waste solvents
- o used equipment lubricating oils

Generators of non-exempt wastes are required to determine if the waste is hazardous and, if so, properly manage and dispose of the

wastes according to the hazardous waste regulations. These regulations include requirements for proper management and the restrictions on land disposal. This is an important fact that oil and gas production facilities must be aware of and comply with as potential generators of hazardous waste.

Impact of Subtitle D

The basic concept for the RCRA Subtitle D program is that it is a program that deals primarily with non-hazardous solid waste. The goals of the program are to encourage solid waste management practices that:

- o Promote environmentally sound disposal methods
- o Maximize the reuse of recoverable resources
- o Foster resource conservation

In the past few years the Office of Solid Waste (OSW) and OWPE have begun to focus more attention on the management of the Subtitle D wastes. These wastes include among others:

- o Oil and gas wastes
- o Mining wastes
- o Municipal solid waste
- o Industrial waste
- o Agricultural waste
- o Demolition debris
- o Municipal sewage sludge
- o Municipal runoff

OSW and OWPE are focussing a good amount of resources on three of these solid wastes: municipal solid waste, mining, and oil and gas. We will now discuss the oil and gas E&P Subtitle D program.

Historically, enforcement of the management of E&P wastes has been performed by the States. Various state agencies have the enforcement authority and state authorities differ greatly in how the E&P wastes are regulated and managed.

With this background, OSW and OWPE have been working on a number of initiatives to determine the current state regulatory and enforcement mechanisms and for developing an overall strategy for regulating and enforcing the proper management of E&P wastes.

An appropriate grant has been active since early 1989 with the Interstate Oil Compact Commission (IOCC) to develop minimum generic state technical and administrative criteria for the management and disposal of E&P wastes. A separate paper on this is being presented in this symposium. The final report on this will be completed in December 1990. Continuing IOCC work in 1991 will be on training of state people, state peer reviews to promote consistency, and a data base for state oil and gas, and state environmental agencies. It is particularly appropriate to have IOCC as an organization of the governors and staffs of the 30 oil states performing such tasks for their own benefit as well as to benefit EPA.

The overall oil and gas strategy is still evolving and being updated with new information. In addition, further definition of the RCRA Subtitle D role may be expected when the Congress passes a new RCRA reauthorization bill. Many expect that this could occur within the next two years.

Based on the current discussions within the Agency and with the states, it appears that some of the elements of the RCRA Subtitle C program may be incorporated into a stronger Subtitle D program. These elements include a routine compliance monitoring program and some type of enforcement authority to aid the states in regulating E&P wastes more thoroughly and with more national consistency.

Summary and Conclusions

We have presented a broad picture of RCRA enforcement in general and as applied to E&P wastes. The exempt and non-exempt wastes have been tabulated. The Subtitle C procedures have been examined and related to the developing Subtitle D scenario for E&P wastes. Some Subtitle C materials will undoubtedly appear among the non-exempt wastes. The relationship between RCRA compliance and enforcement has been discussed.

Conclusions can be drawn that a growing trend toward more comprehensive (tighter) enforcement specifically of exempt and non-exempt E&P wastes is underway, including the elimination of gaps in existing regulations.

TABLE 1

EPA's List of Exempt Exploration and Production Wastes

The following wastes are listed as exempt in EPA's Regulatory Determination submitted to Congress in June 1988.

- Produced water
- Drilling Fluids
- Drill Cuttings
- Rigwash
- Drilling fluids and cuttings from offshore operations disposed of onshore
- Well completion, treatment, and stimulation fluids
- Basic sediment and water and other tank bottoms from storage facilities that hold product and exempt waste
- Accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments
- Pit sludges and contaminated bottoms from storage or disposal of exempt wastes
- Workover wastes
- Gas plant dehydration wastes, including glycol-based compounds, glycol filters, filter media, backwash, and molecular sieves
- Gas plant sweetening wastes for sulfur removal, including amine, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge
- Cooling tower blowdown
- Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)
- Packing fluids
- Produced sand

TABLE 1 (CONTINUED)

- Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation
- Hydrocarbon-bearing soil
- Pigging wastes from gathering lines
- Wastes from subsurface gas storage and retrieval, except for the listed nonexempt wastes
- Constituents removed from produced water before it is injected or otherwise disposed of
- Liquid hydrocarbons removed from the production stream but not from oil refining
- Gases removed from the production stream, such as hydrogen sulfide and carbon dioxide, and volatilized hydrocarbons
- Materials ejected from a producing well during the process known as blowdown
- Waste crude oil from primary field operations and production and
- Light organics volatilized from exempt wastes in reserve pits or impoundments or production equipment.

EPA's List of Nonexempt Exploration and Production Wastes

- Unused fracturing fluids or acids
- Gas plant cooling tower cleaning wastes
- Painting wastes
- Oil and gas service company wastes, such as empty drums, drum rinsate, vacuum truck rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids
- Vacuum truck and drum rinsate from trucks and drums transporting or containing nonexempt waste
- Refinery wastes
- Liquid and solid wastes generated by crude oil and tank bottom reclaimers
- Used equipment lubrication oils
- Waste compressor oil, filters, and blowdown
- Used hydraulic fluids
- Waste solvents
- Waste in transportation pipeline-related pits
- Caustic or acid cleaners
- Boiler cleaning wastes
- Boiler refractory bricks
- Incinerator ash
- Laboratory wastes
- Sanitary wastes
- Pesticide wastes
- Radioactive tracer wastes
- Drums, insulation, and miscellaneous solids.

Subtitle D Universe

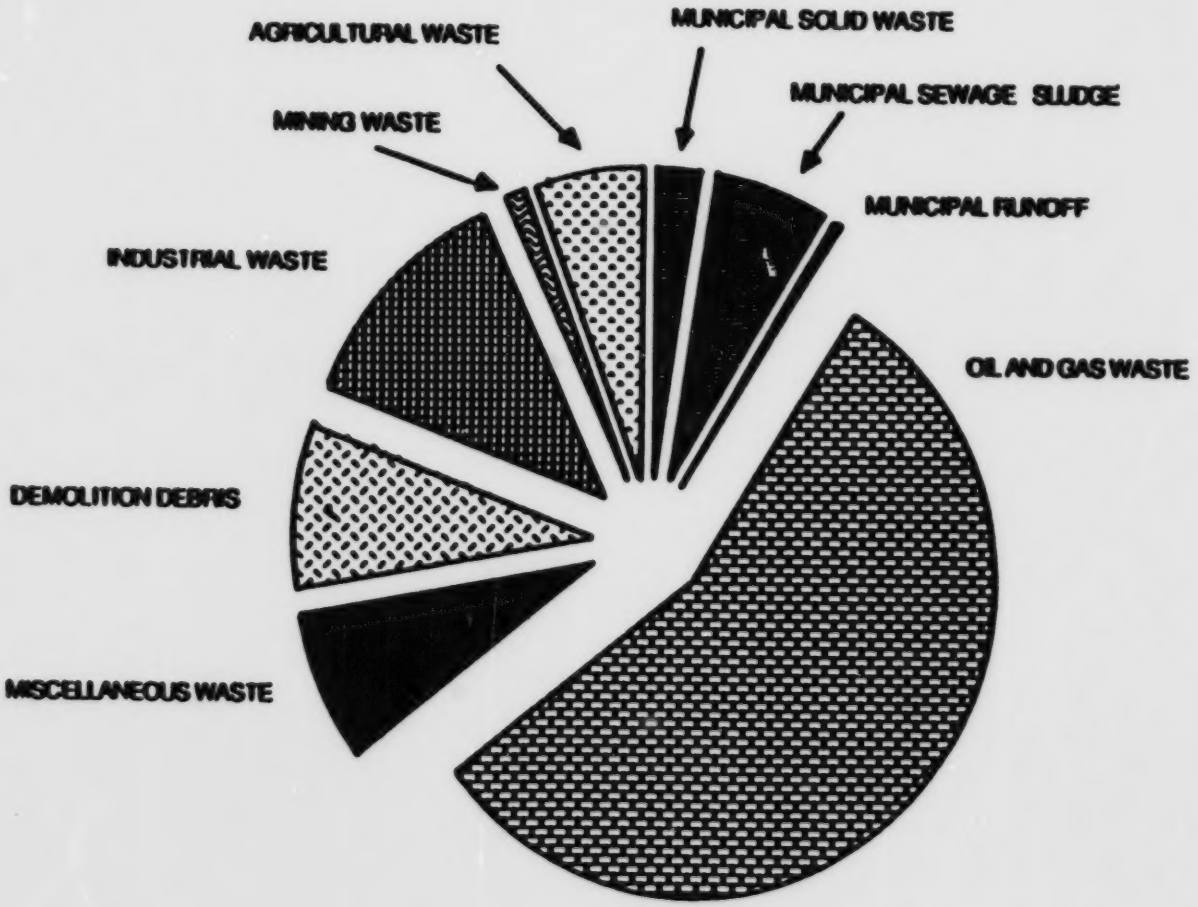

FIGURE 1

COMPLIANCE MONITORING & CIVIL ENFORCEMENT

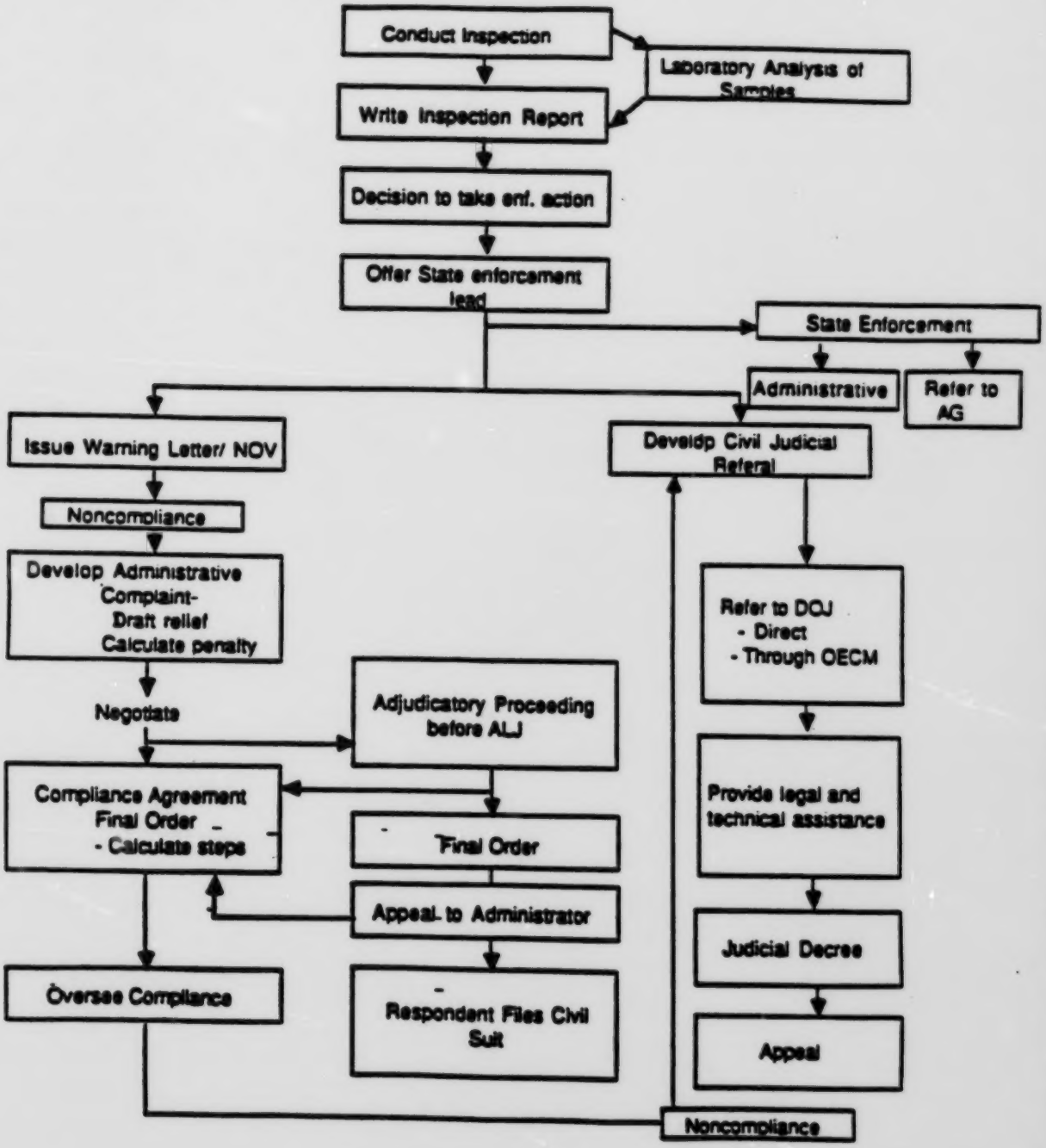

FIGURE 2

THE ECONOMIC IMPACTS OF ENVIRONMENTAL REGULATIONS ON THE COSTS OF FINDING AND DEVELOPING CRUDE OIL RESOURCES IN THE UNITED STATES

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Introduction

This paper summarizes the results of an assessment of the potential cumulative economic impacts of environmental initiatives on U.S. crude oil supplies. The assessment involved a review of selected environmental initiatives that could affect U.S. oil and gas operations. Potential initiatives under the authority of the Resource Conservation and Recovery Act (RCRA), the Safe Drinking Water Act (SDWA), the Clean Water Act (CWA), and the Clean Air Act (CAA) were considered.

The estimated incremental unit compliance costs associated with each initiative were based on the likely practices required to comply with the initiative. From a review of these initiatives, three composite regulatory scenarios were developed, representing low, medium, and high levels of incremental compliance costs. The regulatory initiatives considered under each scenario are summarized in Tables 1 through 4, organized by environmental statute.

The scenarios proposed are intended to represent the range of possible combinations of regulations under consideration, used only for estimating the impact of these initiatives on U.S. crude oil supplies. The estimated unit compliance costs used in this assessment are based on recent analyses performed by the Environmental Protection Agency (EPA) and the American Petroleum Institute (API).

The initial step in the assessment involved estimating economic recovery potential under baseline conditions, which assumed costs of compliance with environmental regulations currently in place. The analysis established recovery potential under baseline conditions, providing the reference case against which the other scenarios were compared.

Future production from four categories of U.S. crude oil resources was evaluated: (1) continued conventional operations in known fields in the Lower-48 onshore, (2) future infill drilling and waterflood projects in known fields in the Lower-48 onshore, (3) future enhanced oil recovery (EOR) projects in known fields in the Lower-48 onshore, and (4) onshore and offshore crude oil fields remaining to be discovered in the Lower-48 and Alaska. For some categories of resource, two

levels of technology were considered -- implemented and advanced -- described below for each resource category.

Summary of Analytical Approach

After currently proved reserves are produced by conventional (primary and secondary) recovery methods, nearly two-thirds of the known U.S. oil resource (over 300 billion barrels) will remain unrecovered, Fig. 1. Although not all of this remaining resource in place could ever be recovered, it represents a substantial target for future advanced recovery operations. DOE estimates that an additional 76 billion barrels of this resource could be recovered at a price of $32/Bbl, given some advances in extraction technologies over the next 15 years (1).

The analysis of the production potential of the known oil resource relies on the Tertiary Oil Recovery Information System (TORIS), developed by the National Petroleum Council (NPC) and maintained at the U.S. Department of Energy (DOE) Bartlesville Project Office (2). TORIS utilizes comprehensive oil reservoir data bases and detailed engineering and economic evaluation models, considering data for individual reservoirs to estimate potential crude oil reserves. The analysis of the undiscovered crude oil resource uses models also developed by DOE in its Replacement Costs of Crude Oil (REPCO) Supply Analysis System (3). This system is designed to determine the cost of finding and developing U.S. undiscovered crude oil resources, of which over 30 billion barrels are economically recoverable at $32/Bbl (4,5).

Cumulative Impacts of Environmental Initiatives

Industry-wide compliance costs could range from $15 to $79 billion initially, and from two to seven billion dollars per year thereafter, assuming the continuation of 1985 levels of drilling and development (4). These estimates assume that the increased regulations would not affect industry activity except in adding costs to operations that would be pursued regardless of the increased regulations.

However, overall industry expenditures will not necessarily increase because of increased regulations. Increased environmental regulations could lead to some previously viable projects becoming uneconomic to pursue. Reduced development of crude oil resources could more than offset the increased compliance costs. Ultimately, overall industry expenditures could decrease as a result of the increased regulatory requirements.

The cumulative impacts of the regulatory initiatives considered are presented below for most resource categories and crude oil prices in terms of the reserves that become uneconomic as a result of increased environmental regulations, and the state and federal revenues (from royalty payments, income taxes, and production taxes) that are not collected as a result of lost reserves.

1. Current Production. This analysis is based on estimated future production from individual reservoirs in nine major oil producing states: California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming. These states were chosen for the availability and comprehensiveness of resource

data, production data, and well counts; because the states represent various stages of oil resource maturity; and because they account for 75% of the remaining oil in place in the Lower-48 states (6).

In the reference case, production projections assumed that historical activities to maintain production are continued in the future. Oil production was assumed to be viable to the economic limit of production, where revenues from oil sales just offset associated production costs.

The impacts of the incremental costs associated with the regulatory scenarios were examined by performing an economic evaluation of each reservoir over its productive life, assuming that the reservoir must incur the incremental costs associated with the regulatory scenario analyzed. The analysis is performed from the perspective of the operator of the reservoir, who would conduct a financial analysis to determine the impact on project profitability from the incremental compliance costs over the life of the reservoir, at the time the regulations go into effect. At this point in time, each operator would make a decision whether to continue with production and incur the incremental costs of compliance, or begin to shut in production. As a result, a considerable portion of current production could be shut in immediately after the implementation of the new regulations. For those reservoirs that continue to operate, the imposition of additional regulations could rapidly accelerate the point of abandonment.

In the 1970s, oil production in the reservoirs analyzed in the nine states peaked at about 4.8 million barrels per day (MMB/D), Fig. 2. By 1989, production had dropped to 2.2 MMB/D, a 55% decrease over the 20 years. This is based on historical, reservoir-by-reservoir production data through 1988 (the most recent date reservoir-specific production data were available). TORIS predictions of reservoir-specific production were used over the 1990 through 2015 time period. In this analysis, 1990 was assumed to be the year the regulations would be implemented.

At an oil price of $20/Bbl, by 1995, production in the reservoirs analyzed in the nine states could drop by about 320,000 B/D in the medium scenario (a 22% decrease over that in the reference case). Production in 1995 could drop by 450,000 B/D in the high scenario, a 31% decrease. In the low scenario, the impact of increased regulations on production in the nine states would be small (less than a 1% change). By the year 2000, production under the medium scenario could decrease 50,000 B/D more than the reference case, a 12% decrease. In the high scenario, approximately 190,000 B/D of production could be lost by 2000, a decrease of 21%. The decrease in production could result in lost reserves of 100 to 1,800 million barrels (MMB) in the nine states over the 1990 to 2000 time period.

The future recovery of the known remaining crude oil resource presupposes that the existing wells and infrastructure in producing reservoirs will be available for the application of future recovery technologies. Moreover, it assumes that operators can retain production rights (leases) to produce oil from these reservoirs. Once abandoned, the resource in these reservoirs becomes essentially inaccessible to future development within the range of prices generally

considered likely over the next 15 to 20 years, even with further improvements in recovery technologies.

The impact of the three regulatory scenarios on the abandonment of crude oil resources in the nine states is shown in Fig. 3. At $20/Bbl, only an additional 2% more of the resource in place in the reservoirs analyzed in the nine states could be immediately abandoned (in 1990) under the low scenario than that abandoned in the reference case at the same point in time. Under the medium scenario, 23% more of the resource in place could be immediately abandoned, while 30% of the resource could be immediately abandoned under the high scenario.

Assuming no future development in the reservoirs considered takes place, increased regulations can accelerate the pace of oil resource abandonments by approximately ten years. This could result in a significant reduction in the time available for technological development to make a contribution to production from these reservoirs currently on the verge of abandonment.

2. Unrecovered Mobile Oil in Known Fields. Unrecovered mobile oil (UMO) is displaceable by water but left in the reservoir at the conclusion of conventional recovery operations because of reservoir heterogeneity or mobility differences that cause injected water to finger through or around the oil. Producing the UMO requires additional wells drilled at closer spacing, to improve contact with the bypassed and/or uncontacted oil in order to improve waterflood sweep and pattern conformance. Additional improvements in secondary recovery can be achieved with the application of polymers, to help improve mobility, or gel treatments, to reduce permeability contrasts between reservoir layers.

The assessment of the economic impact of environmental regulations on recovering the UMO resource was based on analyses of 700 oil reservoirs in Texas, Oklahoma, and New Mexico (7). The reservoirs are estimated to have originally contained 112 billion barrels of oil in place, representing about one-fifth of the total resource in place in the U.S.

Three recovery processes for improving the producibility of UMO were considered: infill drilling, permeability modification treatments (which directs the flow of injected water to lower-permeability layers containing mobile oil), and polymer-augmented waterflooding (where polymers are added to the injected water to obtain a more favorable water-oil mobility ratio and improve recovery efficiency).

Two technology cases were assumed in the evaluation of UMO recovery potential. The cases were based on two different levels of geologic understanding and using two classes of polymers. The first level, corresponding to technology currently being implemented in the field, reflects limited geologic understanding of reservoir heterogeneity and the technical shortcomings of currently available polymers.

The second level, corresponding to an advanced technology case, assumed an improved understanding of reservoir heterogeneity and improvements in waterflooding techniques that increase the applicability and productivity of these processes, including the development of improved polymers for application in higher temperature and higher salinity settings. This scenario assumed that

sufficient geologic data would exist to characterize the reservoir and delineate it into distinct segments, or facies, with reservoir parameters and heterogeneity relationships developed independently for each segment to allow the operator to undertake a geologically targeted infill drilling program.

Under the implemented technology case at $20/Bbl, the low scenario could result in 300 MMB becoming uneconomic to develop in the three states, 16% of the reserves that would otherwise be economic (Fig. 4). Under the medium scenario, 700 MMB could be lost, 35% of otherwise recoverable UMO reserves. Finally, under the high scenario, 900 MMB could become uneconomic, 43% of UMO reserves otherwise recoverable.

In the advanced technology case, low scenario, 300 MMB could be impacted at $20/Bbl, about 6% of the reference case reserves becoming uneconomic. Under the medium scenario, 1,300 MMB could become uneconomic, 24% of the reference case reserves. Finally, under the high scenario, 1,500 MMB could be lost, 28% of otherwise recoverable reserves.

Under the implemented technology case, public sector revenues associated with UMO reserves development in the three states could decrease by as much as 45%, a $4 billion loss. Under advanced technology, revenues could drop by as much as 31%, a $6 billion loss.

The development of the UMO resource requires that a considerable number of new production and injection wells be drilled. Environmental regulations that apply directly to drilling these wells, such as management and disposal requirements for drilling fluids and area-of-review and corrective action requirements for siting new injection wells, are the most significant environmental cost factors influencing the economics of developing the UMO resource.

3. Enhanced Oil Recovery in Known Fields. Enhanced oil recovery (EOR), for purposes of this study, is defined as the incremental recovery of oil in a reservoir over that which could technically be produced by conventional primary and secondary recovery methods. EOR methods include miscible gas injection (typically carbon dioxide), chemical flooding (normally surfactants and alkalines) and thermal recovery (which relies on the introduction of thermal energy to reduce oil viscosity and increase recovery).

The analysis of EOR potential is based on TORIS (1), containing a data base of over 3,700 U.S. reservoirs, representing over 72% of the original oil resource in place in the U.S.

The implemented technology case for EOR represents technology currently available and proven in successful field applications. The advanced technology case assumes technological improvements resulting from successful R&D, improving reservoir description and EOR efficiencies and expanding the applicability of various EOR processes to a broader range of reservoirs.

In the low scenario under the implemented technology case at $20/Bbl, 100 MMB could become uneconomic; corresponding to 3% of the reserves economic under reference conditions (Fig. 5). In the medium scenario, 600 MMB could be

impacted, 24% of the reserves that could otherwise be economic. Finally, in the high scenario, 800 MMB could be lost, 29% of the reserves that could otherwise be economic at $20/Bbl.

In the advanced technology case, low scenario, 700 MMB of reserves could be lost at $20/Bbl, 11% of otherwise recoverable reserves. In the medium scenario, 2,000 MMB could be lost, three times that lost under the implemented technology case. This represents 36% of the reserves that could otherwise be economic. In the high scenario, 2,500 MMB could be lost, 42% of otherwise recoverable reserves.

This loss in reserves could translate to as much as a 40% reduction in public sector revenues in the implemented technology case, and a 47% reduction in revenues in the advanced technology case, a $2 to $7 billion loss.

The impact on EOR from increased compliance costs is similar to that for the UMO resource. EOR projects also generally require the drilling of additional production and injection wells; however, tertiary recovery projects are also impacted by regulations on the reinjection of produced water. Consequently the incremental compliance costs associated with this activity will greatly influence project economics.

4. Undiscovered Crude Oil Resources. Undiscovered crude oil resources, as defined by the U.S. Department of Interior (DOI) (5), are those resources judged to exist in geologically promising but unexplored areas. The economic feasibility of recovering these resources was determined assuming that the volume of oil associated with a discovery must support all costs associated with its development, including all finding costs. The undiscovered resource base analyzed was based on the most recent DOI assessment (5).

In this analysis, the entire U.S undiscovered crude oil resource base was considered. No exclusions for areas currently under leasing moratoria, such as the Arctic National Wildlife Refuge (ANWR) or certain areas off the coast of California and Florida, were considered. If development in these areas is prohibited or substantially delayed, the impact on undiscovered reserves could be greater than those predicted in this assessment.

The three scenarios considered are expected to all have a significant impact on the economic viability of finding, developing, and producing U.S. undiscovered crude oil reserves. Under the low scenario at $20/Bbl, up to 1,000 MMB could become uneconomic to develop as a result of increased environmental regulations, 9% of otherwise recoverable reserves (Fig. 6). Under the medium scenario, 2,100 MMB could be lost, 18% of otherwise recoverable reserves. Finally, under the high scenario, up to 4,900 MMB could be lost, 42% of otherwise recoverable reserves.

Increased regulations will have the greatest impact on undiscovered oil reserves in the onshore Lower-48. At $20/Bbl, 1,000 MMB could be lost under the low scenario (22% of reserves), 2,100 MMB could be lost in the medium scenario (46% of reserves), and 3,000 MMB could become uneconomic in the high scenario (66% of reserves). Increased regulations will have a lesser impact on the discovery and development of oil reserves in Alaska and the offshore Lower-48 than that on

onshore Lower-48 reserves under the low and medium scenarios. In the offshore and Alaska, the increased costs of environmental compliance make up a smaller portion of total project costs than that in the Lower-48 onshore. Consequently, the environmental initiatives considered under the low and medium scenarios are estimated to have a relatively small impact on project economics in these relatively high cost areas.

Under the high scenario, however, the impacts of increased regulations on undiscovered crude oil reserves in the Lower-48 offshore and Alaska are considerable. In the Lower-48 offshore, up to 1,000 MMB of reserves could be lost, 17% of otherwise recoverable reserves. The impacts of increased regulations on undiscovered crude oil reserves in Alaska could be as high as 900 MMB lost at $20/Bbl, 67% of otherwise recoverable reserves.

The loss of undiscovered reserves as a result of increased environmental requirements could result in as much as a $15 billion reduction in public sector revenues over the life of these projects, a 36% reduction.

Conclusions

The results of this assessment lead to the following major conclusions:

- Depending on the extent of new regulatory requirements, the additional costs of environmental compliance could substantially decrease recoverable crude oil reserves. At a price of $20/Bbl (Table 5):
  - reserves from future infill development in known reservoirs could decrease by 6% to 43%
  - reserves from the application of enhanced oil recovery processes in known reservoirs could decrease by 3% to 42%.
  - reserves from the development of future new reservoir discoveries could decrease by 9% to 42%.
- The abandonment of remaining resources in known reservoirs could be accelerated by approximately 10 years; at $20/Bbl, up to 30% of the resource could be immediately abandoned because of increased regulations.
- The increased costs of environmental compliance reduces reserves under both implemented and advanced technology conditions.

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TABLE 1

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Resource Conservation and Recovery Act

	Regulatory Initiative	Regulatory Scenario		
		Low	Medium	High
1.	Management and Disposal of Drilling Waste	Oil-based muds disposed into lined pits Salt water-based muds disposed into lined pits	Oil-based muds use closed systems Salt water-based muds disposed into lined pits	Oil-based muds use closed systems All water-based muds disposed into lined pits
2.	Disposal of Associated Wastes into Central Disposal Facilities	Liquid wastes into offsite disposal well; solid wastes into nonhazardous waste landfill	Liquid wastes into offsite disposal well; solid wastes into hazardous waste landfill	Liquid wastes into offsite disposal well; combustible solid wastes into incinerator; non-combustible solid wastes into hazardous waste landfill
3.	Upgrading Emergency Pits	All emergency pits must be lined.	Existing emergency pits must be lined; new pits must be replaced with tanks	Tanks must replace emergency pits for both new and existing pits
4.	Replace Workover Pits with Portable Rig Tanks	Required on all rigs	Required on all rigs	Required on all rigs
5.	Organic Toxicity Characteristic Test	Applied to all facilities and new wells	Applied to all facilities and new wells	Applied to all facilities and new wells
6.	Corrective Action (Soil Remediation Only)	Land treatment of hydrocarbon contamination at 50% of tank batteries and EOR projects*	Excavation of salt water contamination at 100% of SWD wells and 75% of EOR projects* and tank batteries Land treatment of hydrocarbon contamination at 50% of tank batteries and EOR projects*	Excavation of hydrocarbon and salt water contaminated sites at same frequency as Medium Scenario

* EOR projects refers to both secondary and tertiary recovery projects

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TABLE 2

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Safe Drinking Water Act

Regulatory Initiative	Regulatory Scenario		
	Low	Medium	High
1. Mechanical Integrity Testing*			
Part 1	No incremental requirements (5-year pressure test)	Pressure test frequency based on corrosive potential of basin	Continuous positive annular pressure monitoring and 5-year pressure test
Part 2	Radioactive tracer test every five years	Radioactive tracer test and noise or temperature log run to injection zone, frequency based on basin corrosivity	Radioactive tracer test, noise, and temperature log run to injection zone, frequency based on basin corrosivity
Non Injection-Related Fluid Movement	No incremental requirements	Oxygen activation log and noise or temperature log run to lowermost underground source of drinking water.	Oxygen activation, noise, and temperature log run to lowermost underground source of drinking water
2. Area of Review (on wells drilled prior to 1984)	No incremental requirements	1/4 mile area of review (AOR) under area permit	1/4 mile area of review (AOR) under individual injector permit
3. Corrective Action (on wells drilled prior to 1984)	No incremental requirements	5% of producing wells within AOR assumed to require remedial squeeze	15% of producing wells within AOR assumed to require remedial squeeze
		10% of abandoned wells within AOR assumed to require reentering and replugging	30% of abandoned wells within AOR assumed to require reentering and replugging
		1% of producing wells within AOR must be redrilled	3% of producing wells within AOR must be redrilled
4. Construction Requirements	No incremental requirements	10% of injectors require remedial squeeze	30% of injectors require remedial squeeze
		2% of injectors must be redrilled	6% of injectors must be redrilled

* MIT Part 1 addresses tubing, casing, and packer integrity. MIT Part 2 addresses fluid movement behind the casing.

TABLE 3

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Clean Water Act

Regulatory Initiative	Regulatory Scenario		
	Low	Medium	High
1. NSPS for Offshore Discharge of Muds and Cuttings*	EPA Approach A (EPA's estimate of facilities affected and associated compliance costs)	API Partial Discharge Limitation Scenario (EPA Approach A with API estimates of compliance costs)	API Zero Discharge Limitation Scenario (API assumption that all facilities are affected, using API cost estimates)
2. NSPS for Offshore Discharge of Produced Water	Existing facilities: no change New facilities: treat to 59 mg/l	Existing facilities: treat to 59 mg/l New facilities: shallow water, no discharge; deep water, treat to 59 mg/l	Existing facilities: shallow water, no discharge; deep water, treat to 59 mg/l New facilities: no discharge all depths
3. NPDES Stormwater Permits	Required for 55% of facilities	Required for 55% of facilities	Required for 55% of facilities
4. Above Ground Storage Tanks	Only leak detection and financial responsibility for new tanks larger than 1,000 barrels	All aspects+ considered for new tanks larger than 500 barrels; financial responsibility for all tanks	All aspects+ considered for all new and existing tanks
5. Ban on Onshore Surface and Coastal Discharge of Produced Waters	No incremental requirements	Ban on discharges from new facilities	Ban on discharges from all facilities

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* See EAI, 1988 (8).

\+ Aspects of regulations include injection and integrity testing, overflow prevention equipment, leak detection equipment, additional corrosion protection, and financial responsibility requirements.

TABLE 4

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Clean Air Act

Regulatory Initiative	Regulatory Scenario		
	Low	Medium	High
1. Onshore Air Toxics Emissions Standards	API Case I scenario	API Case I Scenario	API Case II Scenario
2. Offshore Air Toxics Emissions Standards	California only; no mitigation costs considered	California only; mitigation costs considered	Entire OCS; mitigation costs for California only

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See Jones, Marfin, and Hoffman, 1989 (9)

TABLE 5

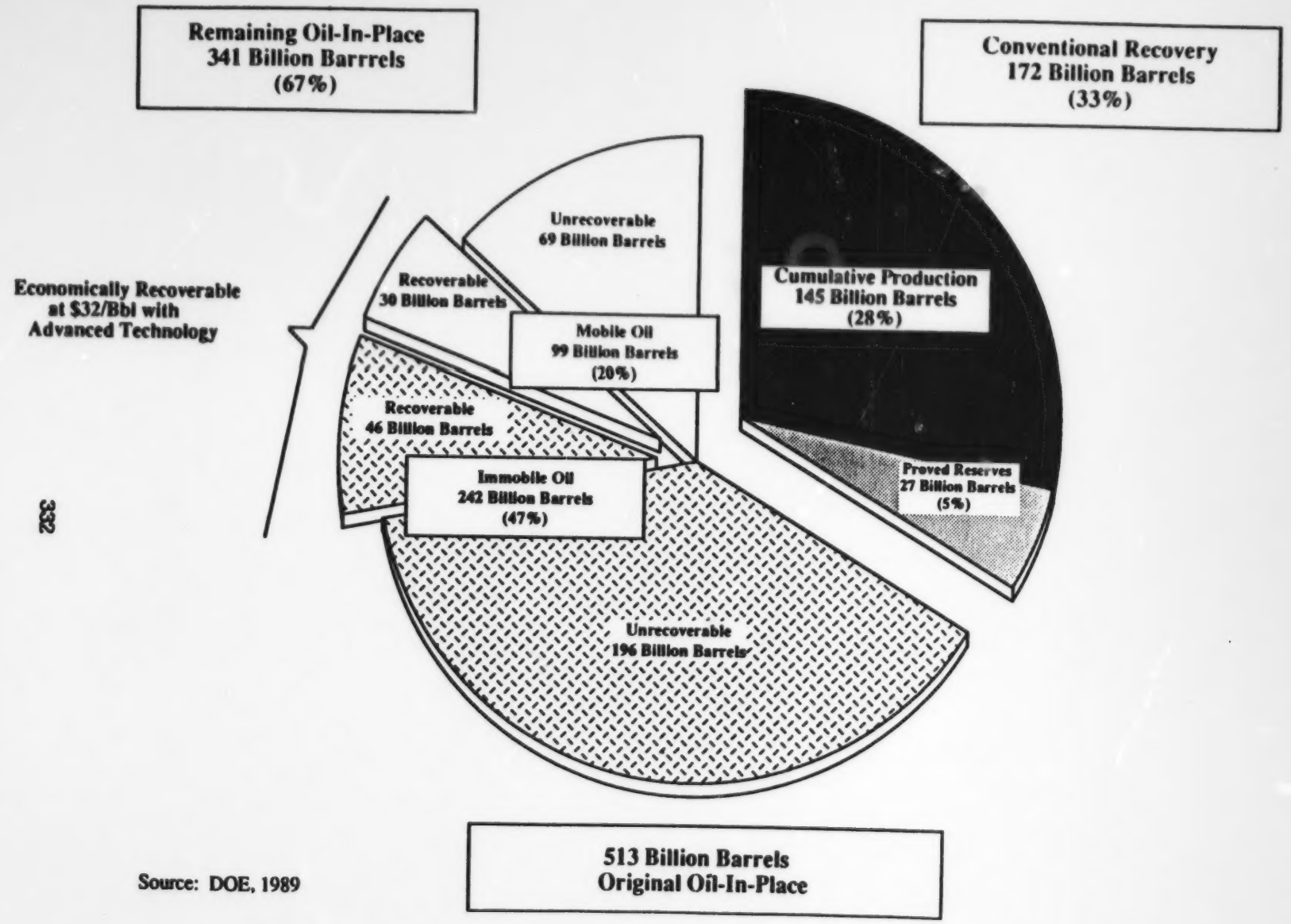
IMPACT OF POTENTIAL ENVIRONMENTAL REGULATIONS ON U.S. CRUDE OIL SUPPLIES AT AN OIL PRICE OF $20/BBL

	Resource Category			
	Conventional Production*	Unrecovered Mobile Oil	Enhanced Oil Recovery	
Undiscovered				
Level of Assessment	Nine States**	Texas, Oklahoma and New Mexico	Lower 48 States (Onshore)	Entire
Implemented Technology				
Resource Lost (%)				
Low Scenario	2	16	3	9
Medium Scenario	23	35	24	18
High Scenario	30	43	29	42
Public Sector Revenues Lost (%)				
Low Scenario	n/a	16	5	7
Medium Scenario	n/a	35	32	17
High Scenario	n/a	45	40	36
Advanced Technology				
Resource Lost (%)				
Low Scenario	n/a	6	11	n/a
Medium Scenario	n/a	24	36	n/a
High Scenario	n/a	28	42	n/a
Public Sector Revenues Lost (%)				
Low Scenario	n/a	7	15	n/a
Medium Scenario	n/a	26	42	n/a
High Scenario	n/a	31	47	n/a

n/a = not analyzed

* Represents incremental resource lost (over the reference case) immediately (in 1990) from premature abandonment

** California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming



Source: DOE, 1989

Fig. 1. Over 300 Billion Barrels of Known U.S. Oil Resources Will Remain After Conventional Production (As of 12/31/87)

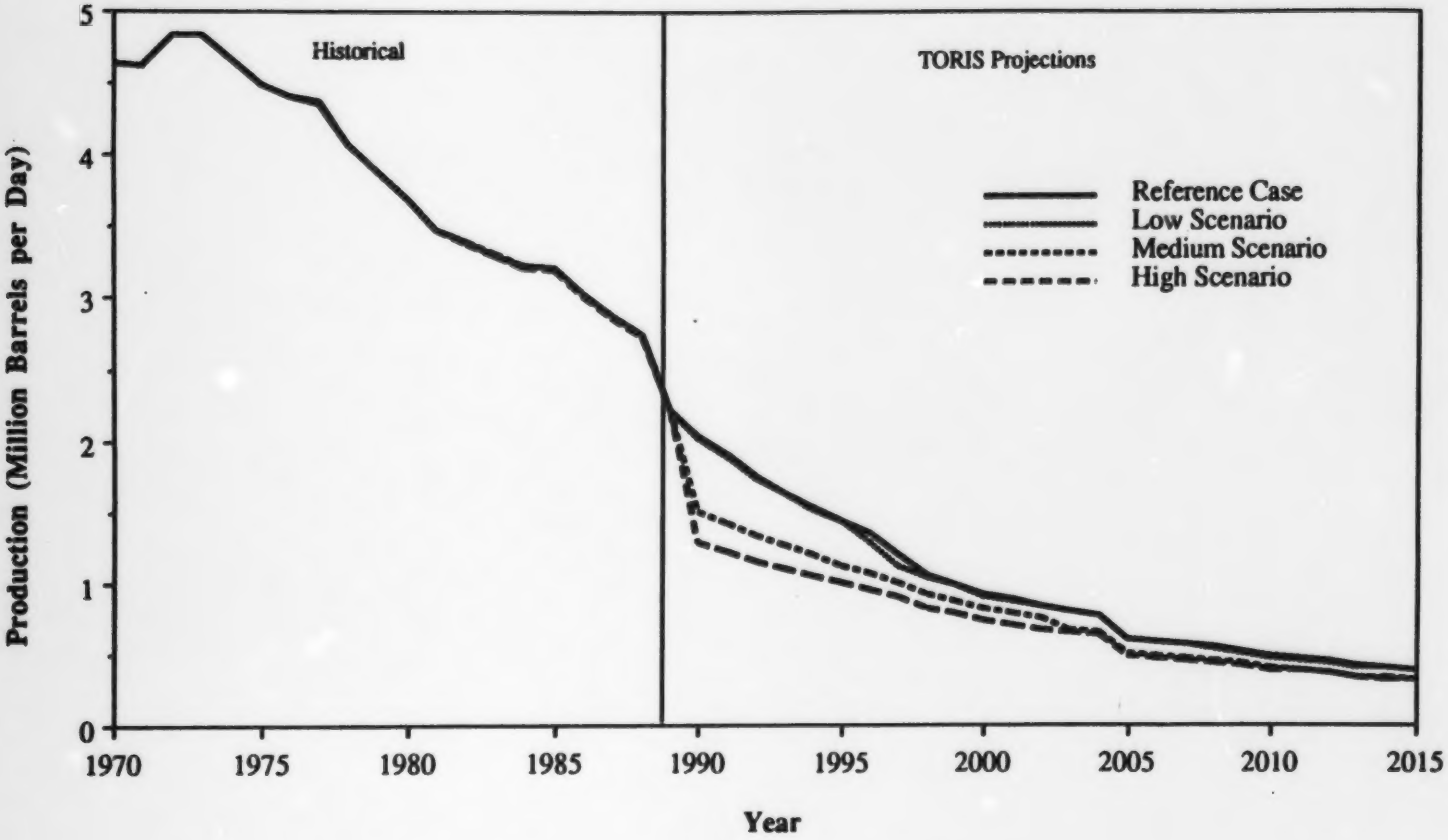


Fig. 2. Impact of Environmental Regulations on Crude Oil Production in the Reservoirs Analyzed in the Nine States ($20/Bbl Oil Price)

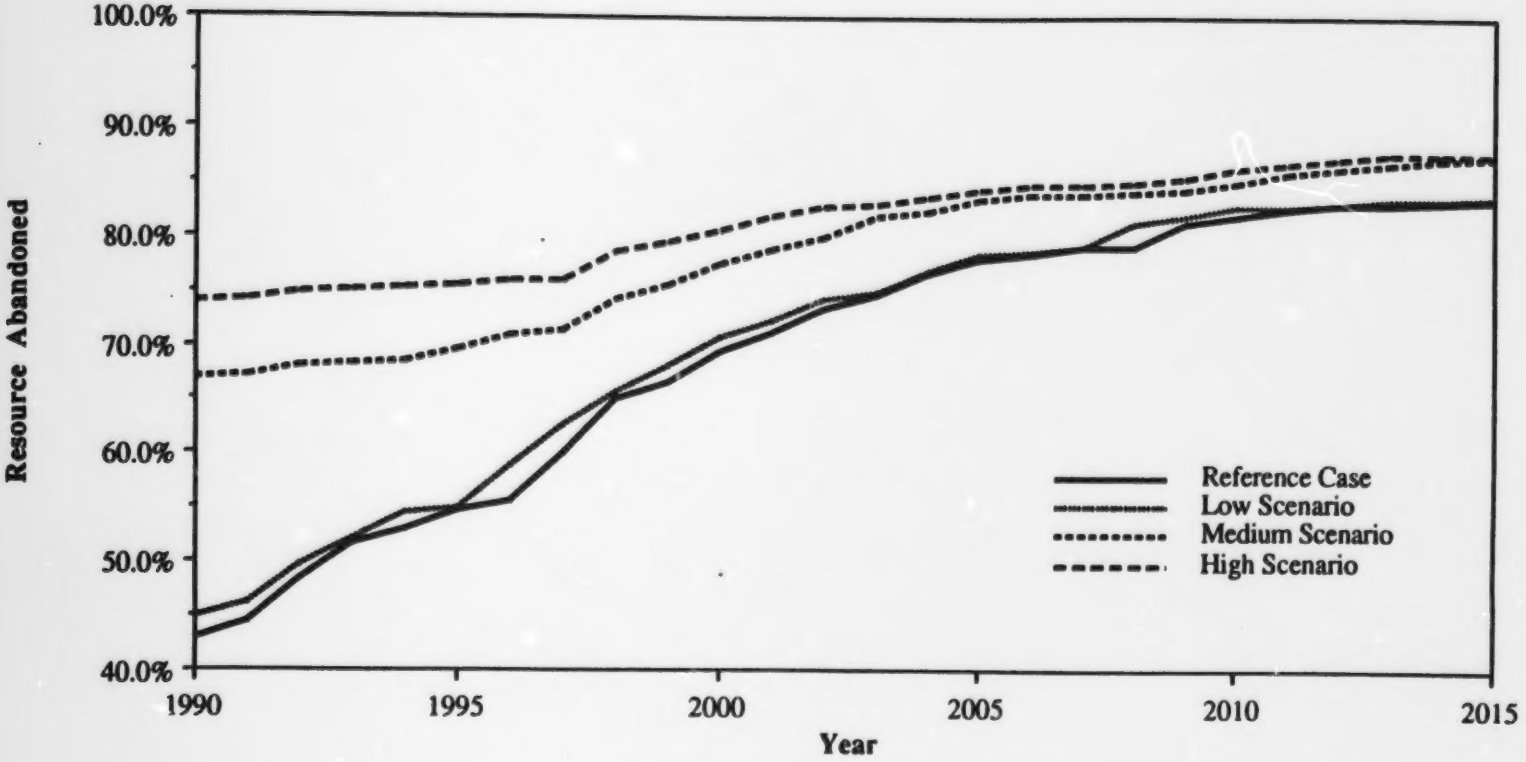


Fig. 3. Impact of Environmental Regulations on Abandonment of the Crude Oil Resource in the Reservoirs Analyzed in the Nine States ($20/Bbl Oil Price)

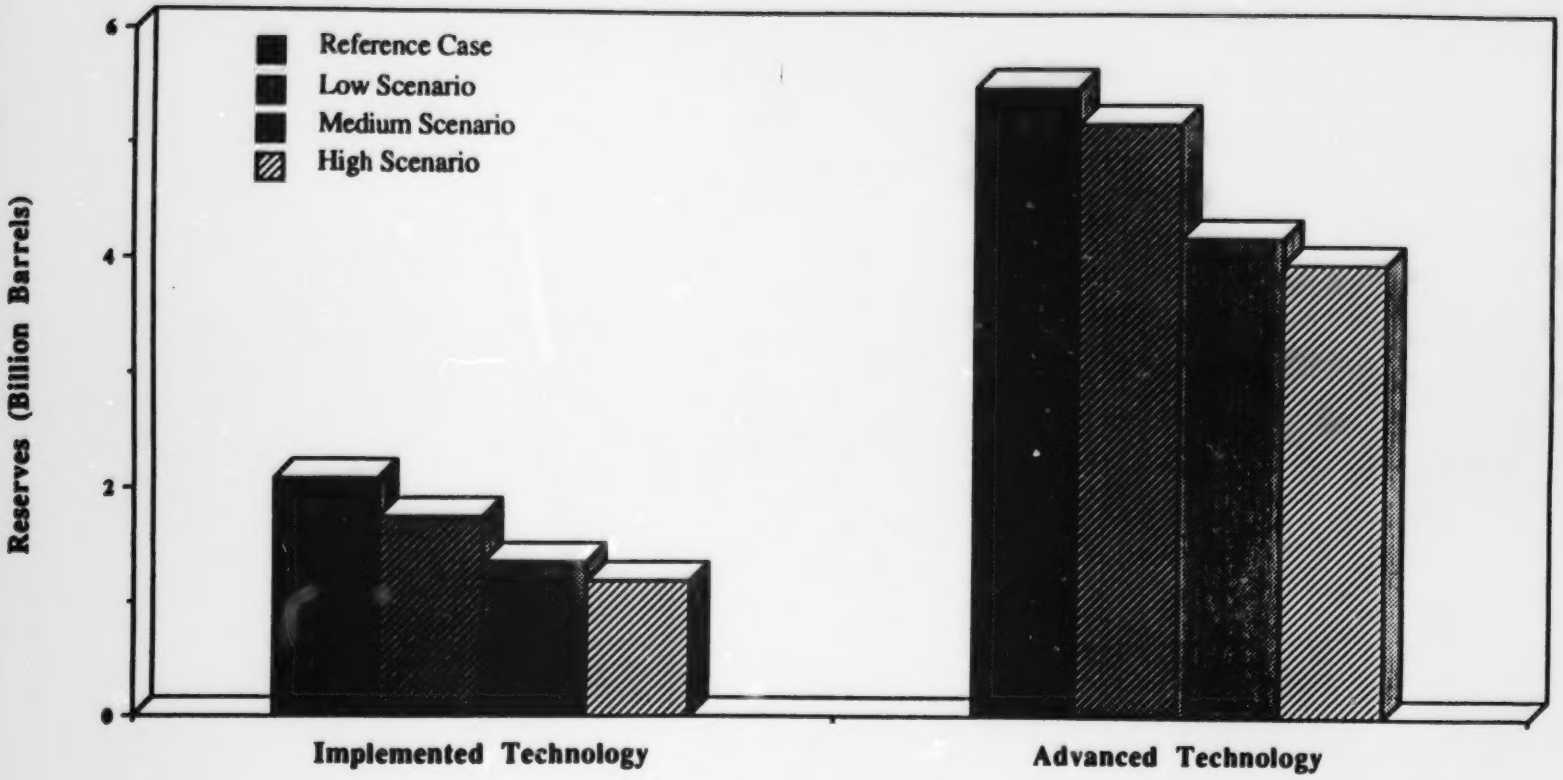


Fig. 4. Impact of Environmental Regulations on UMO Reserves in Texas, Oklahoma, and New Mexico ($20/Bbl Oil Price)

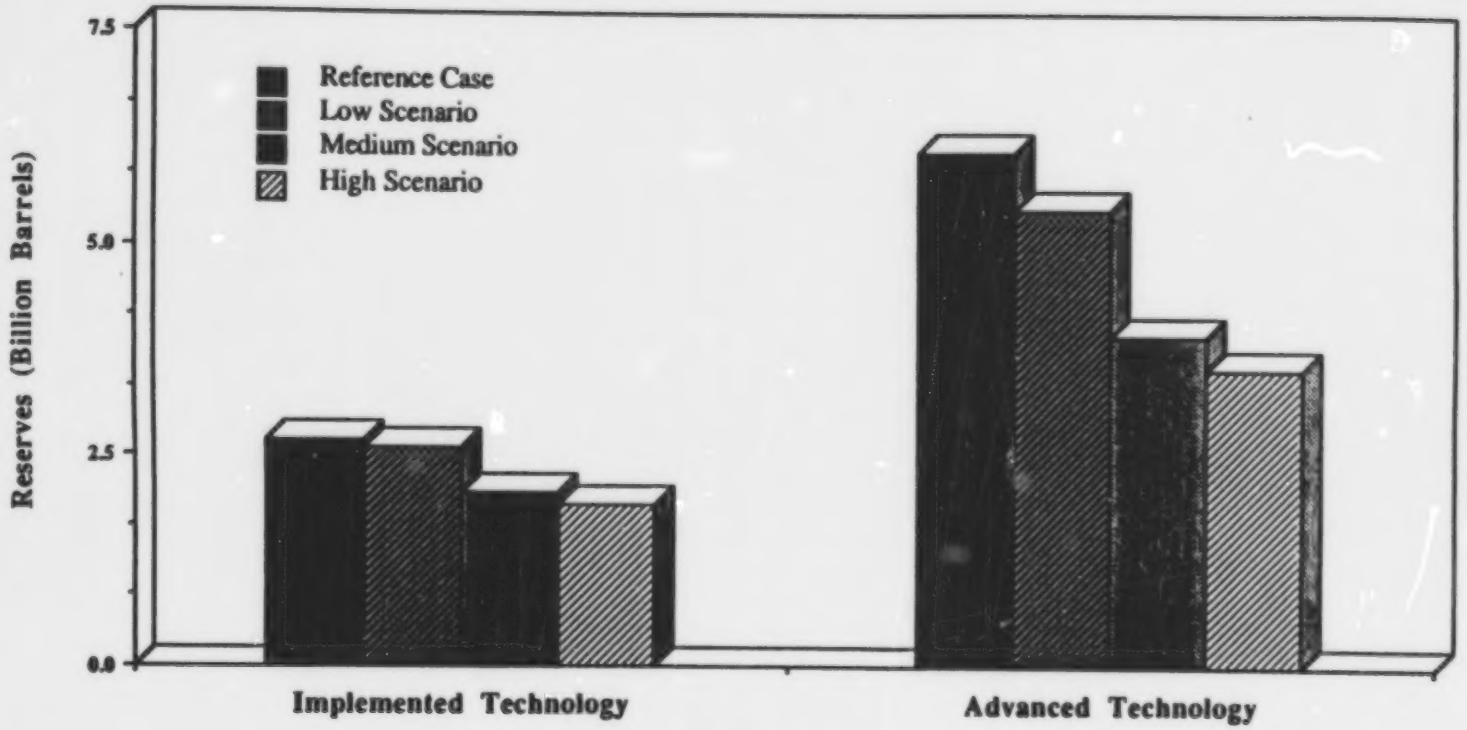


Fig. 5. Impact of Environmental Regulations on EOR Reserves in the U.S. ($20/Bbl Oil Price)

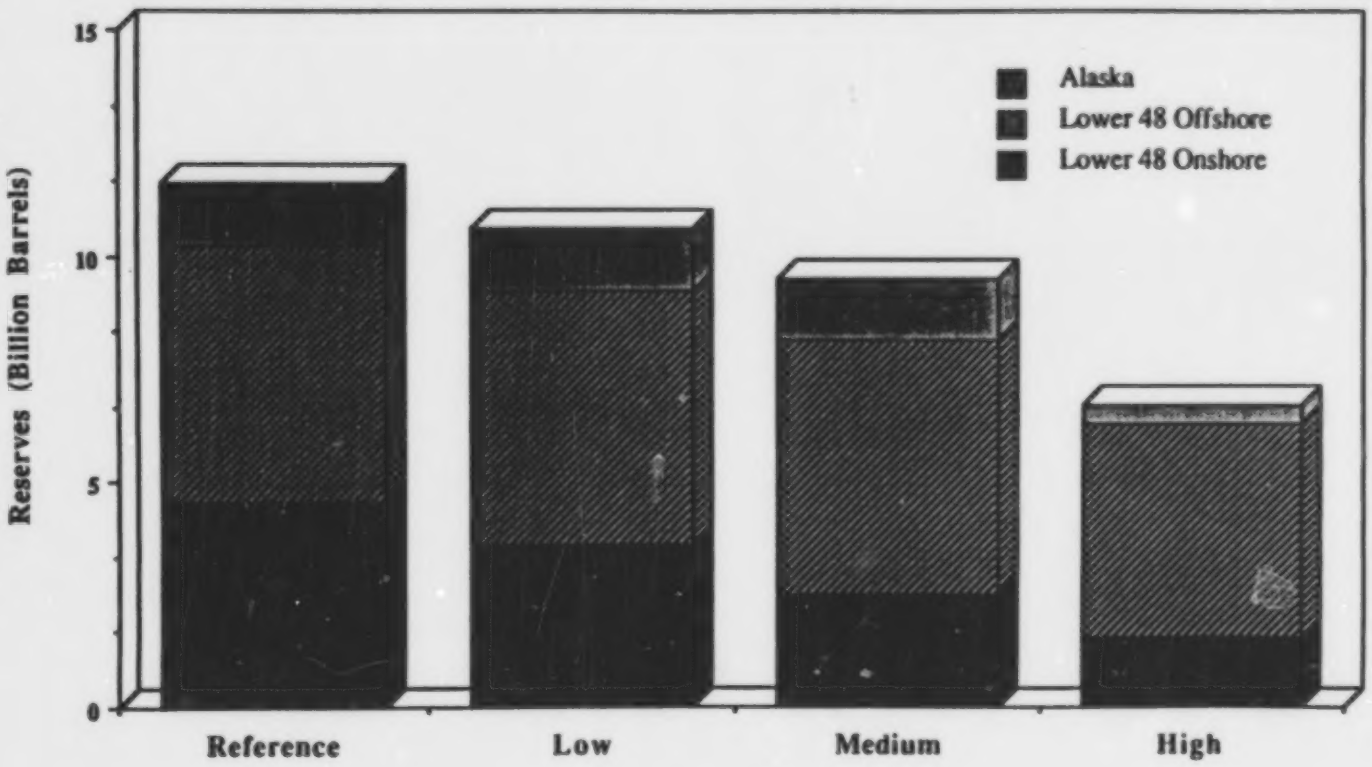


Fig. 6. Impact of Environmental Regulations on Undiscovered Crude Oil Reserves in the U.S. ($20/Bbl Oil Price)

ENVIRONMENTAL AUDITING AT PRUDHOE BAY: A WASTE MANAGEMENT TOOL

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Introduction

Producing oil at Prudhoe Bay required development of new technology for the hostile Arctic climate and the creation of a small industrial enclave in the far north. Gravel roads, five to seven feet thick, were constructed to provide year-round travel across the tundra. Gravel pads are used as drill sites for production wells. Wells are drilled directionally at an angle from gravel drill pads, with 30 to 40 wells per pad, and covering a producing area of up to six square miles beneath the earth's surface. Drilling from a central site minimizes surface disturbance and sharply reduces the need for roads connecting well sites. In addition to drill sites, all buildings are set on gravel pads.

Unlike many fields, which require surface pumps to draw the oil out of the ground, the Prudhoe Bay reservoir has sufficient pressure to force oil to the surface without pumps. Several systems keep the natural oil flow at Prudhoe Bay at a constant level and help recover more oil from the field. Waterflooding, a secondary recovery method began in 1984 with over one million barrels a day of seawater injected into selected patterned wells. Located at the end of West Dock, the Seawater Treatment Plant (STP) filters, deaerates and heats seawater used in waterflooding. After the seawater is heated, it is pumped through pipelines to an onshore injection plant (SIP) where it is pressurized and sent to injection wells. The water intake at the STP is designed to divert fish and marine life and return them, unharmed, to the sea.

Three flow stations on the east side of Prudhoe Bay and one in Lisburne process the oil from the drill sites, separating it from the gas and water. The crude oil from these facilities is shipped by pipeline to Pump Station No. 1 of the trans Alaska pipeline.

The separated gas is transported to a Central Compressor Plant (CCP) for injection into the reservoir's gas cap and to the Central Gas Facility (CGF). The produced water is injected into the oil reservoir as part of the waterflooding program.

More than three billion cubic feet of gas per day can be compressed from about 600 psi to about 4500 psi at CCP. The compressed air is injected into the gas cap were it is stored until a market is found for it.

Designed to handle more than three billion cubic feet of gas a day, the Central Gas Facility (CGF) at Prudhoe Bay is the largest gas handling plant in the world. CGF provides an artificial lift system, another enhanced oil recovery method. Enriched hydrocarbon gas (miscible gas) is injected into the tubing in an oil producing well. The bubbles of gas mix with the oil, making it lighter and more capable of rising to the surface. CGF also produces 55,000 barrels a day of natural gas liquids, which are blended with crude oil and shipped through the pipeline.

A crude oil topping unit (COTU) produces Arctic grade diesel fuel, gasoline and formerly jet fuel for use at Prudhoe.

The Prudhoe Bay Operations Center Wastewater Treatment facility provides sewage treatment services for a population of 2600. The design capacity is 210,000 gallons per day average flow with a maximum monthly average flow allowed by the National Pollution Elimination Discharge System (NPDES) permit of 234,000 gallons per day. The system was designed to provide tertiary treatment including a minimum 95% removal of biochemical oxygen demand (BOD) and suspended solids. The plant, however, consistently achieves removal efficiencies in excess of 98%. Water sludge from the process is thickened and burned on-site in an incinerator operating between 8 and 18 hours a day. Treated effluent from the plant is discharged to a polishing lagoon constructed in a portion of an unnamed lake. The effluent from the polishing lagoon enters the lake by flowing through a shallow weir in a gravel dike.

AAI also operates an offshore exploratory well in nearby Camden Bay, a hazardous waste storage facility (C Pad), a non-hazardous waste disposal facility (Pad 3), two barge

docks, an airfield, hotel facilities, a medical facility, a crude oil testing laboratory, a fire department, numerous warehouses and service shops, and a hundred miles of gravel roads. AAI employees at Prudhoe work round-the-clock on a shift basis. Audit scheduling was therefore designed to involve both shifts.

Disposal and treatment of all wastes produced at Prudhoe Bay are regulated by permits issued by the Alaska Department of Environmental Conservation and the U.S. Environmental Protection Agency. Hazardous waste is carefully managed and consequently has not been a problem in the oil field. The low volumes generated and the nature of the hazardous material have enhanced our ability to properly manage these wastes.

Environmental protection at Prudhoe Bay is a complex task, which starts with the combined efforts of field environmental compliance personnel and personnel from each field facility. Compliance audits are one of many tools employed to ensure environmental protection, especially in the area of waste management. The compliance audit program covered all drill sites, production facilities, drilling, workover and exploratory rigs, field support facilities and waste/wastewater treatment, storage and disposal facilities. Audits were designed to: 1) identify specific compliance problem areas, if any; 2) recommend solutions for any compliance issues discovered, including training programs; and 3) assist in establishing schedules for implementation of solutions.

Materials and Methods

A cooperative problem-solving approach was employed. Inhouse environmental professionals worked closely with facility personnel from all levels. No facility and no area of the eastern half of Prudhoe Bay and Lisburne fields were placed off limits to the audit program. The audits consisted fo five major elements, namely, the audit team, pre-audit questionaires and activities, compliance checklists, employee interviews and facility or site inspections. At the completion of each audit, a summary of findings and recommendations was issued by the Field Environmental Compliance (FEC) Office to the facility's supervisor.

Audit teams were composed of environmental professionals from FEC and the facility's supervisor or his/her designee.

A pre-audit questionaire, including a copy of the compliance checklist and a request to nominate an audit team member and

personnel for interviews, was sent to the facility supervisor three weeks before the audit. The pre-audit questionaire provided a listing of topics to be covered in the audit. Typically, these concerned paperwork or documentation and equipment required by regulations or by the facility's permits, such as the facility's permits, correspondence with regulatory agencies, monitoring reports, any notices of violation, monitoring equipment records, equipment inspection, calibration and/or repair records, waste manifests, records of required training, and the facility's environmental manuals and procedures.

Individual checklists were prepared for each facility. Areas of compliance included NPDES, Prevention of Significant Deterioration (PSD), Air Quality Control, Resource Conservation and Recovery Act (RCRA), Spill Prevention Control and Countermeasures (SPCC) plans, facility-specific waste disposal permits, Class II injection, tundra travel, water use, used oil handling, used drum handling and labeling, waste management, spill prevention, reporting and cleanup, bulk storage tanks, black smoke, reserve, relief and flare pits fluids management, snow removal/gravel carryover, potable water use and wastewater treatment. Regulatory requirements, often not specifically cited in permits but still requiring compliance, were also included.

Input from facility operators is invaluable. Accordingly, interviews were conducted with 25% of each facility's personnel from all levels and job functions. Interview questions were not included in the pre-audit package. Results from the interviews were employed to develop fieldwide and facility-specific environmental training programs.

Each audit included a walk-through physical inspection of the facility and its grounds or gravel pad and access roads following the records/documentation examination and personnel interviews. An exit meeting with the facility supervisor covered specific areas of concern, recommended solutions for problems and scheduling of solution implementation.

A full audit was conducted during one shift and a secondary brief audit was held with the other shift. The brief audit consisted of personnel interviews and a discussion of the previous full audit's findings and recommendations with the facility supervisor. Follow up of easily correctable areas was also performed during the brief audit.

Results

The ultimate test of a compliance audit is not in the elegance of its design but in the results it produces. Although generally accepted audit standards have not yet been fully developed, our audit program has yielded results that can only aid in meeting the company's stated goal of full compliance:

- Verified the company's compliance with federal, state and local statutory and regulatory requirements
- Reinforced top management's commitment to environmental protection
- Increased awareness among supervisors and operators of their permit and other regulatory requirements
- Improved the abilities of facility personnel to determine when and how to make environmental decisions
- Reduced the possibilities of discovering significant "surprises" or recurring patterns of shortcomings in environmental performance
- Identified areas where environmental training is desirable and necessary for ensuring continued compliance
- Increased confidence in management that the environmental activities and efforts of the company are a sound investment
- Identified attitudes or practices that pose a potential for punitive administrative penalties and actions
- Determined the extent to which employees are knowledgeable about and adhering to company policies regarding environmental protection, waste management, etc.
- Confirmed that the communication link between FEC and the various facilities was functioning properly

Conclusions

The current regulatory climate presents a host of potential and unresolved issues-technological, legislative, interpretative, institutional and legal-that may have a substantial effect on the company. The specific outcome is not always predictable or measurable. This is especially true in the area of waste management, which derived the greatest number of benefits from the audit program:

- Refined, facility-specific inventories of the volume and types of wastes generated were developed
- The procedures and facilities in place to handle, store, transport and dispose of the different types of wastes were clarified for field personnel
- Management's confidence that the company's waste management policies and procedures are in good shape and being complied with was increased

•Measures to reduce the volume and/or toxicity of wastes generated were initiated

•Integrating waste reduction into normal operating activities was initiated

To the extent that firms initiate or expand programs, environmental auditing improves the quality and level of compliance. Auditing results in better information about current operations, protects the company from legal, economic and public image problems, and gives management an additional tool in its strategic planning process.

AN ENVIRONMENTAL COMPLIANCE AUDIT OF FOUR OIL AND GAS FACILITIES IN KENAI, ALASKA

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Introduction

Nikiski, a small Alaska town on the Kenai peninsula, 100 km SW of Anchorage, hosts four oil and gas facilities on less than one square mile, including the world's largest ammonia/urea plant, North America's largest exporter of natural gas, and two other petroleum refineries. Located on a deep water port of Cook Inlet, Nikiski is adjacent to 21 oil and gas fields. Along the ice affected coast 15 platforms extract petroleum. Across Cook Inlet is Marathon's Trading Bay facility, the largest oil production facility in North America. Also on the west shore is the Drift River crude oil storage terminal, located in a flood plain dramatically affected by Mt. Redoubt, an active volcano.

Prior to this study there were no comprehensive evaluations of pollution discharges, no compiled records of environmental violations, nor an analyses of enforcement actions for the Kenai industries. The Nikiski facilities selected for investigation because of their proximity to human habitation and potential to pollute. Further research is needed regarding platforms, facilities on the western shore of Cook Inlet, and drilling mud pits.

Research covered a period from the late 1950's to January 1989. More recent events may add to the results but would not affect the conclusions. The four facilities studied are the Unocal-Mitsubishi ammonia/urea plant, Phillips-Marathon-USX natural gas refinery, Tesoro Alaska refinery, and Chevron USA refinery. At Unocal-Mitsubishi over 3 billion pounds of nitrogen based chemicals are produced annually - equal to 2% of the world's annual nitrogen fixing by soil bacteria. Contiguous to the ammonia/urea plant are three refineries that produce and export 2.6 billion gallons a year of gasoline, jet fuel, fucl oils, asphalt, and natural gas. If the refineries combined annual production capacity was placed in barrels and put end-to-end they would encircle the globe with enough left over to reach from Prudhoe Bay to San Francisco.

Method

The research method used is historical in nature. Agency records were systemically collected and evaluated in order to understand past events and analyze trends in environmental regulation. Primary sources of information are inspection reports, permits, enforcement orders, interviews, facility self reporting, letters, and memos. Approximately 5,000 copies were made from a total of 20,000 reviewed pages. Alaska Department of Environmental Conservation (DEC) records were searched in local, regional, and central offices of Kenai, Anchorage, and Juneau. If information was missing or a lack of data was important to document requests were made in writing in accordance with Alaska Public Records Act. Federal records are predominately kept in Seattle and were obtained through the Freedom of Information Act.

Results

The data is organized according to receptor media; that is, air, water, and soils. It is through these media that adverse effects of pollution are transferred between each other and to living things. The total pollution released into each media is listed first then major violations followed by agency responses.

AIR POLLUTION

RELEASES

The four Nikiski facilities release 67 million pounds of air pollutants annually (Table 1). If these pollutants were individually and uniformly distributed across the state National Air Quality Standards would be exceeded to a height of 250 feet.

MAJOR VIOLATIONS

Unocal-Mitsubishi operates in almost daily violation of Clean Air Act limitations on suspended particulates (1). Major spills of ammonia, as much as 800,000 pounds at one time (2) occur on a regular basis, usually two or three times a year (3). Off site air monitoring instruments have exceeded maximum readings for six hours at a time (4). A major air release occurred during unpermitted hazardous waste treatment, when uncontrolled gasses escaped, (5) spreading across public roads and disrupting industrial operations; including the adjacent liquified natural gas storage facility.

Tesoro refinery hydrocrackers exceed nitrogen oxide standards and Tesoro recently built new sources of air pollution without prior authorization, a violation of the Clean Air Act (6).

At the Phillips-Marathon-USX refinery waste oil and gasses were dumped into a flare pit and burned in violation of air quality standards for a period of 18 years (7).

TABLE 1

Annual Air Pollution from the Nikiski Oil and Gas Industry (8)

pounds	pollutant
30,000,000	ammonia
19,000,000	nitrogen oxides*
5,400,000	carbon monoxide*
4,300,000	hydrocarbons
3,400,000	methanol
2,400,000	particulates*
1,000,000	sulfur oxides*
1,000,000	hazardous waste-arsenic
73,000	benzene
45,000	xylenes
32,000	chloroform
31,000	toluene
18,000	1,1,1 trichloroethane
17,000	cyclohexane
13,000	ethylbenzene
4,000	formaldehyde
500	naphthalene
100	lead*
34	ethylene dichloride
22	polycyclic aromatics
5	ethylene dibromide
2	cadmium
1	chromium
67,000,000	

(* Clean Air Act permitted releases).

AGENCY RESPONSE

In response to over 15 years of violations at Unocal-Mitsubishi, DEC has done the following: stopped recording violations (9), requested EPA not to issue an enforcement letter to Unocal-Mitsubishi (10), promised to refrain from fines or legal action for past violations (11), amended state air quality regulations thereby creating less stringent standards (12), and allowed Unocal-Mitsubishi to operate with an expired permit.

In response to violations at Tesoro DEC reissued an air permit.

In response to over 18 years of violations at Phillips-Marathon-USX, DEC issued a Notice of Violation.

WATER POLLUTION

RELEASES

The Nikiski facilities release 6.5 million pounds of waste into Cook Inlet each year (Table 2), which does not include the weight of polluted water.

TABLE 2

Annual Surface Water Pollution from the Nikiski Oil and Gas Industry (13)

pounds	pollutant
3,300,000	nitrogen compounds*
2,400,000	sulfuric acid*
690,000	unidentified suspended solids*
140,000	oil and grease*
18,000	zinc*
7,000	ethylene glycol
2,500	1,1,1 trichloroethane
970	chromium*
460	phenols*
550	sulfide*
370	polynuclear aromatics
200	cyclohexane
200	xylenes
130	benzene
60	toluene
7	ethylbenzene
7	arsenic
7	cadmium
4	nickel
4	cyanide
6,500,000	

(* Clean Water Act permitted releases).

MAJOR VIOLATIONS

The ammonia/urea plant was formerly owned by "Colliers" at which time self monitoring reports were intentionally falsified (14). More recently Unocal-Mitsubishi dumped hazardous waste containing

methanol and formaldehyde into Cook Inlet in violation of RCRA and the Clean Water Act (15). Unocal-Mitsubishi allowed the out fall diffuser to become plugged, then cut the diffuser off, thus negating the permit mixing zone calculations (16).

Over 200 unpermitted underground injection wells are used to dump water contaminated with ammonia and arsenic (17). A Unocal underground injection well exceeded pressure limits and injected prohibited waste, violations of the Safe Drinking Water Act permit (18).

Tesoro did not meet schedules for effluent bioassays.

Phillips-Marathon-USX uses unpermitted shallow underground injection wells to dump contaminated water. Also the facility discharges waste water into Cook Inlet without a Clean Water Act permit.

AGENCY RESPONSE

After nearly a decade and a half of documented ground water pollution by Unocal-Mitsubishi neither state nor federal authorities have taken enforcement actions.

When Tesoro production capacity increased, EPA and DEC simply allowed total pollution to increased (19) despite the fact bioassay studies have shown the effluent so toxic that all species subjected to a 1:10 dilution were killed and even a 3% mixture severely affected reproduction (20).

SOLID WASTE

RELEASES

Unocal-Mitsubishi disposed of 70,000 pounds of drummed hazardous waste by giving it to the City of Kenai for road oiling (21,22). No records of manifests, storage facility permits, or other required RCRA reports were found in the public record.

Each day Unocal-Mitsubishi dumps 10,000 pounds of metal sludges containing high levels of zinc (250,000 ppm), arsenic (3,300 ppm), copper (25,500 ppm) and lesser amounts of chromium, nickel, lead, and cadmium, into gravel pits (23,24,25). In addition, Unocal-Mitsubishi generates one half million pounds of catalyst each year. Used catalysts are dumped on the ground, used for fill, and buried (26). Laboratory testing in 1983 indicated used catalysts are hazardous waste due to high levels of extractable chromium. Unocal-Mitsubishi repeated laboratory analyses until the catalyst passed EP-tox tests. Intra-laboratory differences of more than 100, between three separate labs were not resolved (27), and the catalyst waste was declared non hazardous.

In a single year as much as 640,000 pounds of hazardous waste were spilled at the ammonia/urea plant (28). Between 1983 and 1985 there were seven reported major hazardous waste spills (29). Halogenated solvents are disposed in waste oil (30, 31), a practice clearly prohibited by the RCRA.

Tesoro generates 10,000,000 pounds of elemental sulfur each year which is dumped on the ground without a permit.

Phillips-Marathon-USX filter charcoal contaminated with arsenic and mercury (32) is used for disposal, masquerading as "road oiling dust control", rather than managed as solid waste. The most recent disposal involved 22,000 pounds of contaminated charcoal. Waste oil, possibly mixed with RCRA listed hazardous waste, is dumped on the ground with the intent of disposal (33).

Chevron dumps "oil filter waste" on roads for the purpose of disposal (34). In the past Chevron dumped hazardous waste in unpermitted pits on Chevron property (35, 36).

MAJOR VIOLATIONS

Unocal-Mitsubishi ignored RCRA regulations and stored over 140,000 pounds of hazardous waste in violation of 40 CFR 270.71. Further mismanagement resulted in unreported spillage from bulldozers knocking over drums of hazardous waste (37). Hazardous waste tanks (190,000 pounds capacity) do not have RCRA tank permits (38).

Tesoro dumped hazardous waste into unlined pits dug in porous soils (39), spread it on public roads (40), illegally stored and shipped hazardous waste (41), and hazardous waste solids were allegedly recycled for disposal pits walls (42).

Chevron adds hazardous waste to consumer products (43). A disposal method not approved by RCRA; because, solids derived from listed hazardous waste are not eligible for recycling (40 CFR 261.1).

AGENCY RESPONSE

EPA cited Unocal-Mitsubishi for violating the same RCRA storage regulation as many as three times in only four months (44).

At Tesoro, EPA imposed fines totalling $57,750 (45, 46).

Chevron was twice served Notices of Violations by EPA for noncompliance with hazardous waste laws (47).

Discussion

AIR POLLUTION

EPA has delegated authority of the Clean Air Act to DEC. Therefore inspections, reporting, and enforcement are the responsibility of the state. As a result of state authorization DEC lowered state air quality standards; that is, an opacity limit was raised, for the purpose of allowing Unocal-Mitsubishi to gradually come into compliance. However for almost two decades the ammonia/urea plant has exceeded even the generous variance allowed by DEC. When EPA threatened to override DEC primacy the state commissioner pleaded with EPA to not issue an enforcement letter. Unocal-Mitsubishi also leveraged the DEC by pressuring the Alaska legislature. As a result of testimony at public hearings, Unocal-Mitsubishi sent a letter protesting proposed ambient air standards. The protest letter was sent all Alaska's congressmen, governor, and every state representative and senator (48).

Inability and unwillingness to enforce are further illustrated by DEC knowingly allowing construction of new air pollution sources by Tesoro in violation of the Clean Air Act. Despite ongoing violations, the Tesoro permit was renewed. Tesoro and DEC justified renewing the air permit because it would be more economical to bring the facility into compliance at some time in the future.

Prior to DEC acquiring primacy of the Clean Air Act, Alaska had state air quality regulations at which time facilities such as oil and gas platforms and incinerators were required to both obtain operating permits and report regularly. However since assumption of Clean Air Act primacy DEC has substituted less stringent air quality regulations; thus, effectively deregulating oil and gas platforms and large incinerators such as the oily and chemical waste incinerator located at Trading Bay, across Cook Inlet from Nikiski. These deregulated sources are not insignificant. Oil and gas platforms, off shore from Nikiski, emit approximately 34% of the 35 million pounds/year of NO_x produced in upper Cook Inlet. Additional deregulation is evident by the fact that none of the oil and gas platforms; including three with permits, report, measure, or are required to even estimate SO_x emissions. Despite a history of almost daily violations at multiple facilities, no evidence was found of state assessed fines.

SURFACE WATER POLLUTION

EPA retains authority for enforcing the Clean Water Act. The four Nikiski facilities discharge waste water to Cook Inlet. A review of discharge monitoring reports (DMRs) indicates a high level of

compliance. The exception is an intentional falsification of ammonia/urea plant DMRs. A search of state and federal records did not reveal this enforcement case. However personal communication with a state regional supervisor and enforcement officer revealed the nature of this case. A criminal conviction was reportedly plea bargained for a fine of approximately $400,000, one of the highest ever assessed nationwide, at the time.

GROUND WATER POLLUTION

DEC regulates the discharge of waste water to the land. However, neither the Unocal-Mitsubishi 200 underground injection wells nor a leaky Unocal-Mitsubishi waste water pipeline nor the several dozen discharges of Phillips-Marathon-USX are permitted. Likewise none of the Nikiski facilities have the state required permits or plans for waste water sludge disposal.

An example of state inability to enforce is illustrated by a Unocal-Mitsubishi response to DEC requests for monitoring wells. Unocal-Mitsubishi claimed their carcinogenic arsenic-containing hazardous waste is "less toxic than table salt" (49). Unocal-Mitsubishi used human subjects for a taste and odor panel to screen for contamination. Unocal claimed "Should any contaminated water somehow reach a domestic water well, the water would acquire a detectable taste or odor prior to becoming hazardous." (50). Eventually Unocal-Mitsubishi groundwater investigations were transferred from RCRA to CERCLA (51). A CERCLA study found that contaminated ground water and unpermitted air releases resulted in a Hazard Ranking System score over 30, high enough for National Priorities List nomination (52). Later, ground water compliance issues were reassigned back to RCRA. There are neither plans nor schedules to evaluate the contamination issues under either RCRA or CERCLA. In the future DEC may request Unocal-Mitsubishi to study their ground water problems.

SOLID WASTE

Solid waste regulations are a complex web of state and federal laws. State laws regulate non-RCRA solid waste. None of the facilities have solid waste permits yet they all dispose of solid waste on their facilities. No record was found of any attempt by DEC to require solid waste permits of these facilities. Additional evidence of widespread disregard for solid waste regulations is borne by the fact that.60 nearby pits used for disposal of drilling muds have no permits.

RCRA waste is regulated jointly by EPA and DEC. EPA actions have resulted in several major compliance actions with fines. Additional federal actions include forcing Tesoro to submit closure plans for

unlined hazardous waste surface impoundments. DEC actions are limited to a few simple reports by an inexperienced inspector. DEC has never taken a RCRA sample from any of the four Nikiski facilities (53).

Conclusions

I. Environmental laws with sole federal jurisdiction; such as the Clean Water Act in Alaska, have the best compliance record.

II. When the state is authorized to enforce federal environmental laws; such as, the Clean Air Act and Resource Conservation and Recovery Act, compliance is limited to incidents of federal involvement.

III. State environmental laws without federal oversight are virtually without compliance and enforcement; such as, solid waste, waste water, and waste water sludges.

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ENVIRONMENTAL EVALUATION OF OIL DRILLING AND COLLECTION SYSTEM- A CASE STUDY FROM INDIA

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PREAMBLE :

Environmental evaluation of oil drilling and collection[1] system was first made during 1982 in a limited area of Eastern Region of Oil and Natuaral Gas Commission (ONGC) and Oil India Limited(OIL) in Assam. Environmental damage as a result of these activities observed at that period was so prominent that a follow-up visit[2] was made in 1985 to have an impact study and also to evaluate the status of pollution.

Increaseddemand on petroleum:

Consumption of petroleum products in India is in leaps and bounds. Trend in rise is steep: In seventies, when the rise was about 5%, between 1981 and 1987, it was 40%; from 49.8 million tons in 1988-89 to projected 95 million tons in 1999-2000, the rise is 91% About 56% of this accounts for transport sector. The vehicles population from meagre 10 million in 1987 is expected to be a little more than 42 million in 2000 AD. So there will be no respite from the steep rise of consumption of petroleum. India having a poor foreign exchange reserve with large deficit budget can not afford the luxury of importing more crude. Only recourse left is to exploit more from domestic crude.

Extended Exploration Activity

The area of operation of both ONGC and OIL has been extended throughout the length and breadth of the country. An environmental audit thus becomes all the more important. Study of environmental impact, then and now, corrective measures already taken and scope of further improvement, necessity of development of standards for such activities as a guideline

to the explorers becomes very significant. For convenience however, the study is restricted to on-shore production only.

Environmental damages caused:

Though "API Recommended (RP.51 First Edition). On-shore Production Operating Practices for Protection of the Environment was published in 1974, production of oil started in Eighteenth century and fields visited during the study were operational from 1966.

a) Due to drilling operation:

In 1982, about 20 drill-sites were visited and adverse environmental impact noticed were:

Major impact

.Spoiling surrounding land (Blight):
Many temporary sheds are built and lot of excavation takes place to set the drilling rig. After drilling operations were over, all scars are left behind.

.Destroying plants and vegetation including crops.

.Oily patches around drill-sites were a common sight.

Medium impacts

.Threat to animal life due to grazing in oil covered land -cattle-death was reported due to grazing in such areas. All rejects of drill-sites were nowere contained.

Major impacts

.Destroying rare fibre-producing worms (Muga) which are unique and specific of North Eastern states of India - a specie very sensitive to noise and may be to hydrocarbons often due to burning of left over crude and waste lubricants, are getting extinct and has become an endangered specie in operational areas where it grew in abudance. This has adversely affected the rural economy of flood-prone population.

.Top soil, ground water and surface water was badly affected. Damage to soil was irreversible. Oil found in shallow hand tube wells for drinking purposes were found infested with oil.

.Possible threat to human health is yet to be assertained.

Flowing of oil laden waste from so-called evaporation pits supposed to be used for evaporation of the formation water by using natural gas only added another dimension of the problem of unburnt hyudro-carbons in addition to highly saline oily waste flowing down to cultivable land, streams and finally the river sources.

b) Due to collecting system

In oil collecting stations (OCS) or Group Gathering stations (GGS), the environmental impact was more persistent and acute compared to drilling sites which was a transitory phenomenon. Due to againg of the filed oil & gas flows out with 30% to 40% (Sometimes as high as 95%) formation water. In the OCS, crude and gas is separated through Emulsion Treater under physico-chemical process, adding chemical at 60°c to 65°c. The treated water from Emulsion Treater was taken to evaporation pits where with the help of natural gas, this water is supposed to be evaporated, neither being completely evaporated nor the natural gas was completely burnt. This resulted in air, water and land pollution. In some ideal cases only, the formation water was injected back into formation for pressure build-up in the reservior.

Due to round-the-clock flare in the evaporation pits neither fenced nor enclosed with asestos sheets or protective brick walls, the tea bushes nearby were affected reducing tea crops and paddy crops did not give the desirable yield. Due to incomplete combustion, unburnt hydrocarbons released into the environment, thick smoke was a common sight. The effect of this on plant, vegetation or even human health could not be estimated. A Schematic diagram of a GGS is shown in Fig. 1, appendix.I.

Desirable practice

API RP51 "is an industry consensus on recommended onshore production operation practices for protection of the environment" Though it can "improve company profits by approaching environmental consideration in and orderly and planned manner", the realisation did not come fully at least to

company till the study was made in 1982. The other company by tradition had developed good environmental practice-injected the treated formation water into dry well or well sunk for this purpose and monitored ground water around such injection well to see if it was polluted:

-even in case of necessity to flare the unutilized gas either surplus due to less off-take by customers or lean gas at low pressure, flaring was either stopped or brought to a bare minimum during October to December when seed formation in paddy took place. The excess natural gas is released in a controlled way atop a stack at a higher level.

Actual practice:

In spite of a claim to have total evaporation and zero discharge from the evaporation pits, in actual practice, it was found to let out the formation water into the environment having a COD upto 15680 mg/l and oil and grease upto 1261 mg/l (copies of analysis reports placed at Table 1 and 2, Appendix II & III Such discharges into adjoining land caused stagnation with top layer of oil completely spoiling the vegetation, the fertile paddy land sometimes converted to stagnant pool.

Follow-up

In earlier findings of 1982, environmental damages were reported and remedial measures were suggested to follow desirable practices.

Therefore, a second impact study and also an evaluation of the pollution status were done by the Central Board in association with the Assam Pollution Control Board in April-May, 1985. The objectives of the present study were:

a) to evaluate the present status of the Group Gathering Stations(GGS) in the Lakwa Oil-field in respect of flaring, wastewater disposal, oil-spill etc. and to make a comparative study between the conditions prevailing in 1982-83 and those at present.

b) to study the performance of the Effluent Treatment Plant (ETP) at Lakwa.

c) to study the conditions of GGSs and Oil-fields at Rudrasagar, Galeki and Borhola areas.

d) to study the conditions of drilling sites in general.

e) to study the water injection system recently introduced in some of the oil-fields of ONGC in Assam.

f) to make a general assessment of the environmental damages that may be caused by oil-exploration and to suggest probable remedies to abate such pollution.

During the period from April 30 to May 3, 1985 the three oil fields of Lakwa, Galeki, Rudrasagar areas of ONGC were photographed, and Borhola area was inspected. The ETP at Lakwa was visited to study its performance, critical areas were photographed and samples of the wastewater at the different stages of treatment were collected for analysis of their oil and grease and pH content. The report of the analysis is annexed at Annexure IV at Table 2. In table 3, the range of parameters like oil (free and emulsified), pH, Total alkalinity, salinity, TDS and COD as observed in different units of the ETP for April 1985 are shown.

The proposed site for water-injection system, which was under construction at the Galeki fields was also inspected. During discussion, it was revealed by the ONGC authorities that only the tube-well water would be injected to the reservoir down below for building up pressure in the oil bearing strata.

Findings

Overall findings

At the first impression it appeared that the oil-fields belonging to ONGC situated at Lakwa, Rudrasagar, Galeki and Borhola were better maintained when compared to the conditions prevailing in 1982-83. Also, there was a change in the attitude of the people manning these installations, and apparently prevention of pollution was getting some priority. There was an appreciable improvement in cleaning the environment.

Production wells.

Some of the drilling well revisited bore scars of original drilling and evidences of oil-spill and leakages-

GGS:

Improvement was seen, streams were cleared of oil, it was expected that surrounding areas might be fit for vegetation after sometime. Some of the flare pits were found still kept open. Seepages through broken masonry walls of evaporation pit appeared to be a common feature.

Effluent Disposal Methods

In the oil fields surveyed, the wastes are being disposed in the following manners.

a) Physico-chemical treatment

b) Disposal in wells

c) Vaporisation in flare-pits

d) Releasing the effluent without treatment into environment.

Physico-Chemical Treatment:
In the Lakwa fields, the ONGC has installed one ETP which is functioning well. It was understood that it would take the entire effluent from the Lakwa area. The ETP, apart from treating the effluent is also helping in recovering substantial quantity of slop oil(Fig. 2, Annexure IV

The treatment was found to be effective and result of analysis of grab sample for one month is shown in range (Analysis report of effluent is annexed at Table 3, Annexure V)

Disposal in Wells

Disposal of the effluent in wells is practised in some of the oil-fields of OIL. Its efficacy and long-term effects on groundwater, if any, quantity-disposal, and cost-effectiveness are yet to be studied.

Vaporisation in Flare-pits:
This system is in vogue in most of the GGSs. But whether it really evaporates the entire quantity of effluent is not known. In all probabilities, it does not. These pits are often flooded and the effluent goes out. It is not possible to contain the effluent water entirely within the pits.

Release of Raw Effluent:
Instances of occasional, accidental and even regular discharge of untreated effluent into the environment are prevailing in some areas.

Wash Water Tank:
In Rudrasagar area, ONGC authorities are experimenting with wash-water tank to remove oil from the effluent by applying heat and using compressed air.

RECOMMENDATION

In the oil-fields, environmental awareness must be given top priority and all sections of people should be made aware of the necessarty environmental protection.

It is essential that ETPs are constructed in all the oil-fields for the treatment of entire effluent. The treated water may be allowed to be discharged or it may be suitably used.

The practice of evaporating the effluent at evaporating pits should be discontinued.

However, so long the evaporation pits are in use, masonary walls and other structures are to be so designed and constrcted to ensure total elimation of spillages or seepages. Discharge of effluent to suitable underground strata or into dry-wells may be practised but it must be seen that such effluent does not mix with the aquifers of shallow or deep-tube wells.

Ways and means must be found out to use the natural gas, so that the practice of flaring may be discontinued except for emergency and for other technical reasons.

Regarding drill site, the American Petroleum Institute recommendations (API RP 51, October 74) should be strictly adhered to.

Continuous monitoring and adoption of anti-pollution measures by inhouse committees should be encouraged.

Dissolved air floatation system whereever possible and is found to have practical application may be attempted.

Continuous monitoring system for NO_xHC and SPM should be established at selected locations:

In-depth study of effects of oil exploration, drilling and production activities on the silk-worms, ground-water in particular and other flora and fauna is general should be made.

Evaluation of Minimal National Standards (MINAS) for Industrial and other Discharges.

Water Pollution Control Programmes are designed essentially to maintain/ restore the natural water bodies to various designed best use. General approach to achieve this objective would be using any one of the following tools or combination thereof:

- Control of Pollution at the sources to the extent possible giving due regard to techno-economic feasibility and social expectation.

- Optimal utilization of assimilative capacities of natural water bodies to minimize investment in pollution control at source.

Maximization of reuse/recycle of domestic and industrial wastewater on land for agricultural use of industrial purpose.

- Minimization of pollution control requirements by judicious location of industries and relocation of industries wherever necessary.

- Introduction of discipline in water abstraction and wastewater discharge and a sense of water conservation.

- River flow regulation.

This water quality management in any region involves manipulation of several tools individually and in combination to achieve the end objective which in this case, is the optimal utilization of water resources.

The industry-specific effluent standards which will be evolved at the national level is to be recognised as "Minimal National Standards". This model envisages treatment of all wastes to certain minimum standards regardless of the type of wastewaters and locations. No State Boards are required to relax on the "Minimal National Standards", but if the quality criteria of the ambient water at some reaches warrants stricter effluent quality the State Boards shall prescribe that and thus would make the Minimal National Standards altered to suit the location. This model is effective in halting the obvious pollution immediately and envisages a steady progress in meeting the water quality objectives. It also provides a fair degree of the flexibility to the Regulatory Authority for Control of Water Pollution

The minimum treatment to be provided in any wastewaters aims at the removal of the following pollutants:

- Pathogens by effective disinfection
- toxic substances
- colloidal and dissolved organic solids

- mineral oils
- adjustment of PH

The Minimal National Standards, abbreviated as MINAS are evolved for different types of industry considering the treatability of the wastewaters and the various unit processes and unit operations that are available for treating such wastewaters. The unit processes and unit operations are the building blocks and each has an associated factor and pollutant removal factor. Any combination of unit processes and unit operations provides a stage of treatment, the performance of a stage of treatment is expressed by the percentage of removal of pollutants. The percentage of removal does not increase continuously but by quantum as stages of treatment are increased. To elucidate further, the domestic wastewater is subject conventionally to the three stages of treatment: primary, secondary, and tertiary. With each stages of treatment the quality of the treated effluent, if expressed by the conventional parameter BOD, improves from BOD removal efficiency of 30 percent by primary stage to 85 percent by secondary stage to 95% by tertiary stage of treatment.

The acceptability of the MINAS is linked to the techno-economic acceptability of the suggested stage of treatment to the polluted which is possible by linking the annual cost of pollution control measures (capital and capitalized operation, maintenance and repair cost converted into annual burden) to the annual turnover of the industry. The stage of treatment whose annual burden remains within the critical percentage of annual turnover is generally accepted as minimal stage of treatment and the concomitant effluent standards is the MINAS. There may be medium hard industry for whom the annual burden of the minimal stage of treatment should remain above the critical percentage of annual turnover but below the super-critical percentage. The industries for whom the annual burden of the minimal stage of treatment remains above super-critical percentage of annual turnover are obviously hard industry. What percentage of annual turnover is critical and super-critical is to be decided by the Industry Committee.

Though the MINAS for oil Refinery has been developed in 1981-82, the field of oil drilling operations with collection and transport system was so far not done in India. Recently in Dec.'89 M/s. Engineers India Ltd., a Govt. of India undertaking has been engaged by the Ministry of Environment & Forests, Govt. of India to develop the MINAS. While developing the MINAS, stress has been laid to method of disposal of waste drilling fluids, its probable effects on soil, method of treatment of formation water, efficacy of different process units in an effluent treatment plant alongwith the use of chemicals alongwith cost economics thereof.

Effluent Treatment Plant & Lakwa

Plant Lay-out

The plant lay-out is shown in Figure 2 of Appendix IV. The process units comprise of

Surge ponds - 2 Nos of 5000 M capacity

API Gravity Oil Seperator - 2 Nos

Flash mixer - 2 Nos

Flocculator - 1 No

Clarifer - 1 No

Guard Pond - 1 No of 5000 M capacity

Sludge lagoons - 2 Nos of 4000 M capacity

Other units like slop-sump, supernatant sump, sludge sump slop tank etc.

Process Units

A. Physical process :

(1) Surge pond

The effluent from various GGS enters into the surge pond (one number to act aas stand-bye), the measurement of the flow being made with a Parshal flume (Photograph 38). This unit alongwith the stand-bye unit like a balancing tank shall effect uniform hydraulic and pollutant loading and in case of plant upset/excess flow, the stand-bye unit will be used for storage. This unit is provided with oil-skimming arrangements with manually operated scooping devices to remove free oil which passes into the slop-off sump.

(ii) API Separators

The effluent from surge pond flows to the API Seperator at controlled rate where the free oil is removed. The industry claims 80% removal efficiency of free oil in this unit. Two channels are provided, one to act as stand-bye, in which free oil is removed continuously from the top of the effluent with the help of wooden paddles moved in a chain. The top oil is collected in a slotted pipe which is taken to the slop oil sump. The oil-free effluent passes into the Flash mixer.

B. Chemical process :

(iii) Flash mixer

Rapid mixing of chemicals like $FeSO_4$, alum lime and bentonite in the effluent takes place. Usually a dose of 300-500 mg/1 of alum, 250-300 mg/1 of lime and 20 mg/1 of bentonite are recommended depending upon the oil concentration of the effluent from API seperator - lower does for the range of 1000 to 2000 mg/1 of oil and higher does for the higher range of 2000 mg/1 to 4000 mg/1. On the day of the visit, alternatively 400-500 mg/1 of ferrous sulphate with 250 mg/1 of lime and 20 mg/1 of bentonite was used.

(iv) Clariflocculator

The effluent after thorough mixing of chemical moves into this unit. With the slow-moving paddles attached to the operational bridge and the sludge scraping arrangements at the bottom, it looks like any other clarriflocculator of a water treatment plant. The sludge collected at the centre of the unit is passed of to the sludge-sump from where the sludge is pumped to the sludge lagoons for drying. The clear effluent overflows to the launder arrangement. There is arrangement for skimming of floating oil in the operational bridge. The skimmed oil is taken to the slop-oil sump and the clear effluent passes into the guard pond.

(v) Guard pond

This unit is another tool in the process to have contol over the treated effluent before final discharge. With a hay-filter box at the discharge end, the residual oil traces shall be absorbed by the hay. This unit provides for 24 hours storage. There is arrangement for PH adjustment by adding sulphuric acid.

(vi) Sludge lagoons

Chemical sludge from the clarifier and oily sludge from the API Seperator are pumped to the sludge lagoons. These units are just for thickening and drying of sludge having suitable inlet and outlet arrangements. The supernantant liquid is drawn off at 3 3 different levels to the wastewater treatment plant. Oil skimming arrangements are provided in this unit also the skimmed oil being sent to the slop-oil sump. The thick sludge with or without burning will be used for land-fill.

(vii) Ancilliaries/Facilities

Chemical storage for 15 days, office-cum-operators room, Laboratory and other facilities, chemical preparation tank, pump houses for pumping of sludge and slop-oil comprise of other facilities in the wastewater treatment plant at Lakwa.

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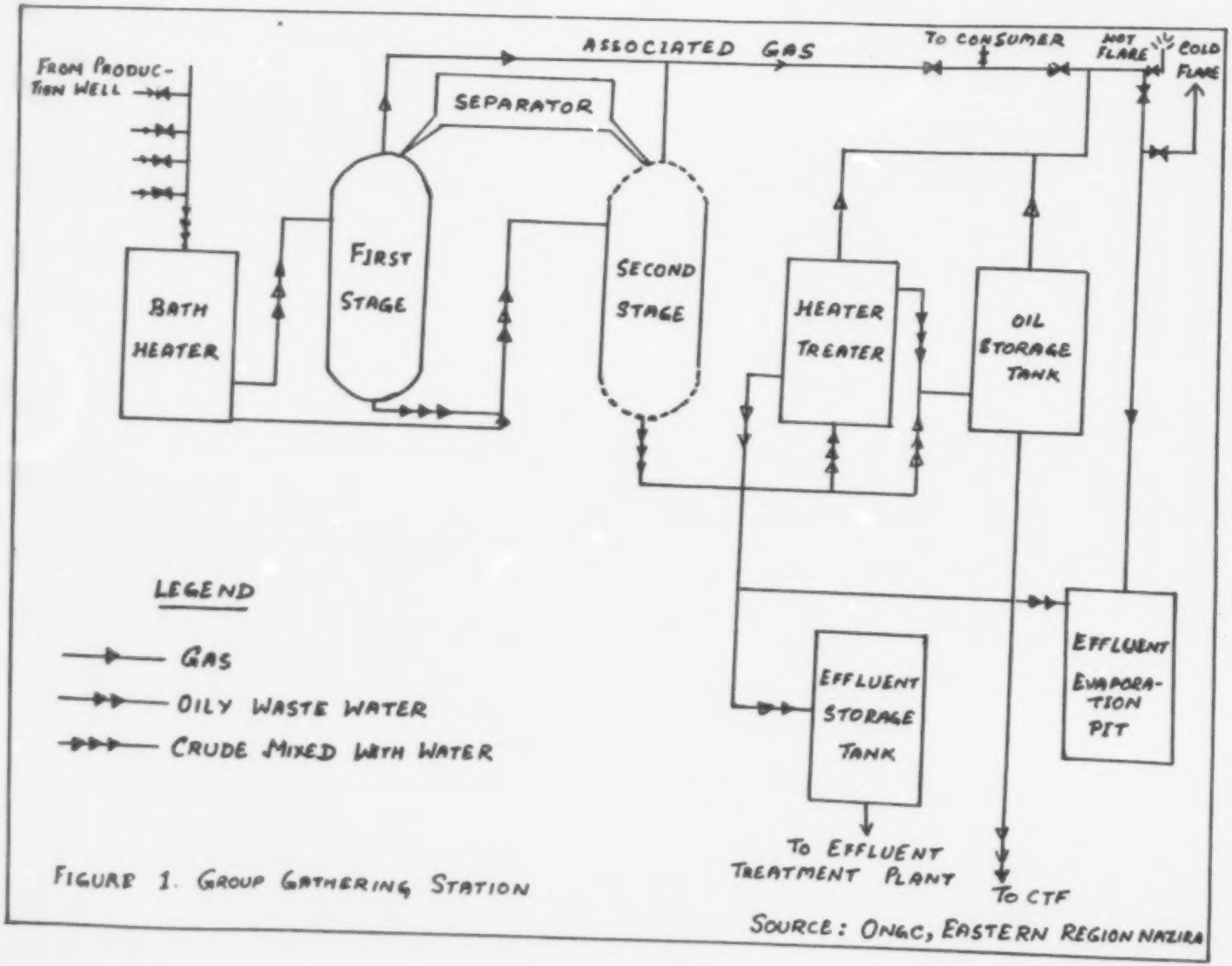

FIGURE 1. GROUP GATHERING STATION

SOURCE: ONGC, EASTERN REGION NAZIRA

ANNEXURE I

Annexure II

Table 1
Analysis Report of Treated Water
from GGS II,Lakwa

REPORT ON CHEMICAL ANALYSIS

A. Laboratory Reference No	Tech. 267/82
B. Source of the Water	Water from G.G.S.II,Lakwa
C. Place of collection	Lakwa.
D. Sampled by	Shri K.C.Baruah, Executive Engineer.
E. Date of Collection	2-6-82 at 16.50 Hrs.
F. Date of receipt	4-6-1982
G. Sent by	Executive Engineer, B.P.C.W.P. Assam.
H. Sender's reference no.	Letter dated 4th June,1982

PHYSICAL APPERANCE-OILY AND TURBID
CHARACTERISTICS

pH	(mg/l)	7.3
C.O.D	(mg/l)	3,120.00
Oil and Grease	(mg/l)	872.00
Kjeldahl Nitrogen as N	(mg/l)	12.8
Chloride as Cl.	(mg/l)	2,200.0
Total Solids	(mg/l)	6,880.0
Total Volatile solids	(mg/l)	1,988.0

Annexure III

Table 2

Analysis Report of Treated Water
from GGS III,Lakwa

A. Laboratory Reference No.	Tech. 268/82.
B. Source of the water	Water from G.G.S. III Lakwa.
C. Place of collection	Lakwa.
D. Sampled by	Shri K.C.Baruah, Executive Engineer,
E. Date of Collection	2-6-82 at 17.30 Hrs.
F. Date of receipt	4-6-1982
G. Sent by	Executive Engineer, B.P.C.W.P. Assam.
H. Sender's reference No.	Letter dated 4th June, 1982.

PHYSICAL OILY AND TURBID (SAMPLE)

pH	(mg/l)	7.1
C.O.D	(mg/l)	15,680.0
Oil and Grease	(mg/l)	1261.0
Kajeldahl Nitrogen as N	(mg/l)	5.6
Chloride as Cl.	(mg/l)	500.0
Total Solids	(mg/l)	3,920.0
Total Volatile Solids	(mg/l)	3,640.0

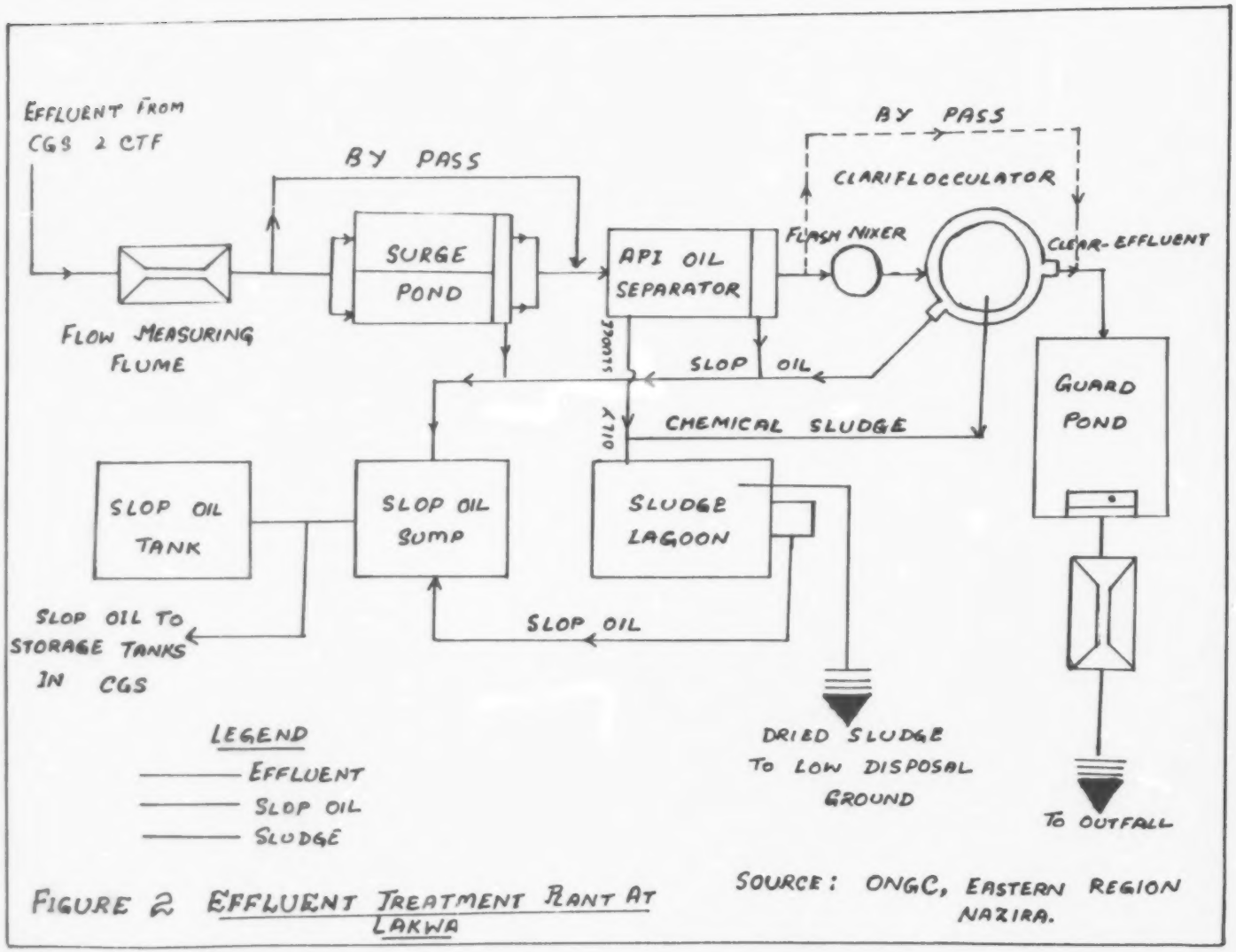

FIGURE 2 EFFLUENT TREATMENT PLANT AT LAKWA

SOURCE: ONGC, EASTERN REGION NAZIRA.

ANNEXURE IV

Annexure V

TABLE 3
PERFORMANCE OF ETP AT LAKWA AS OBSERVED
FOR THE MONTH OF APRIL,1985.

Parameters	Oil (mg/l)			Total Alkalinity mg/l	Salinity mg/l	TDS mg/l	COD mg/l
Unit of ETP	free	Emulsified	pH				
Surge pond inlet	from trace to 2,500 to 15,000	5,650 to 9,500	7.6 to 8.0				
Post API Seperator	nil to trace	1,400 to 4,100	7.9 to 8.2				
Guard pond outlet	nil	6-11	7.9 to 9.5	62to 390	865to 9500	1,600to 2,730	127 to 240

Source: ONGC

ENVIRONMENTAL PROTECTION PLANNING FOR PRODUCED BRINE DISPOSAL IN SOUTHWESTERN SASKATCHEWAN NATURAL GAS FIELDS

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Introduction

Southwestern Saskatchewan and adjacent areas of southeastern Alberta, Canada have extensive deposits of shallow sweet natural gas in the Milk River, Medicine Hat, and Second White Specks formations. A total of some 40 000 gas wells has been drilled throughout this area located about midway between Calgary, Alberta and Regina, Saskatchewan (2). Saskatchewan's portion of this field, termed the Hatton field, extends west from Swift Current, Saskatchewan to the Alberta border. The gas, at depths of some 500 - 600 m, is easily and relatively inexpensively produced using conventional methodologies.

Southwestern Saskatchewan has a continental climate, with warm, dry summers (mean daily July temperature: 19 C) and cold, dry winters (mean daily January temperature: -14 C). It is one of the most arid regions in Saskatchewan (mean annual precipitation: about 350 mm), and precipitation is highly variable year to year. Annual evapotranspiration generally exceeds precipitation substantially. Prevailing winds from the north, west, northwest and southwest have an important influence on evaporation rate. Drying action of these winds during the frost-free period is significant from a produced fluid-disposal perspective.

Land use in the area is agricultural, either ranching or cultivation of annual cereal crops, primarily wheat. Human population is sparse. Cultivated soils are predominantly medium-textured brown chernozemic loams. There are also extensive areas of aeolian sand, most of which are thinly vegetated grazing lands. Groundwater, especially in the

extensive sandy areas, often occurs at a depth of a few meters.

Dugouts and shallow wells incorporating wind-driven (and more recently, electrically powered) pumps are used to access the shallow water. The presence of this widely available, easily obtained, and relatively high-quality groundwater is key to the ranching economy and also during historic times to the substantial populations of ungulate wildlife.

Much of the ranching area, particularly in the 2000 km^2 Great Sand Hills, is relatively inaccessible and is considered by many to be a unique wilderness worthy of enhanced environmental protection. This concern, together with a more general emphasis on shallow groundwater protection, increases the priority on environmentally responsible gas development, including disposal of blow-down brines.

The Problem

Hatton wells normally operate with minimal environmental impact. The wells are periodically inspected visually, and gas meters, which may be remotely located, are read at weekly to monthly intervals. Associated disturbances are minimal, raising few direct concerns even in environmentally sensitive areas. The principal environmental concern during operation is co-production with the gas of varying volumes of moderately salty brine termed blow-down fluid or water of condensation.

Gas/water production ratios vary both over different parts of the Hatton field and over the average 20-year-plus life of a given well. Reduction of hydrostatic head by producing the water in the well bore enhances gas-production rates. Within the Saskatchewan portion of the field, brine production ranges between 0 to 0.3 m^3/well/day (1), while production rates for the whole field (Saskatchewan plus Alberta) range between 0 and 1 m^3/well/day (2). Given that there are some 3500 - 4000 producing Hatton wells in Saskatchewan, with substantial additional drilling anticipated, cumulative brine production is substantial.

Brine characteristics vary somewhat from well to well, and from different formations. Table 1 summarizes blow-down fluid composition from the three producing formations (2).

Several options exist for producing and collecting the blow-down brine. Operators may produce the brine at each wellsite, resulting in up to three brine collection and containment facilities per km^2 ($8/mi^2$). This approach tended to be adopted at older wells. More recently, some operators are moving produced water with the gas via flow lines to either centralized metering or compressor stations. Flow lines must be below the frost line (about 2 m), and collection systems designed to allow efficient gas/water movement. Frequent line pigging is necessary. Central collection allows more efficient handling, including facility construction and reduced trucking and other costs. The wide dispersal and discontinuous arrangement of production areas complicates brine-disposal options, both economically and logistically.

Historical Practices

Enhanced environmental awareness and rapid development in the Hatton field have increased concern with brine-disposal practices in government, industry and the public. Prior to 1987, the small quantities produced in Saskatchewan were usually blown to atmosphere, coating plants and the ground surface with fine clays and releasing soluble materials, primarily salts, into the environment (2).

Concern with implications of this practice for groundwater, soils, vegetation and livestock/wildlife grew in the 1980's, accentuating increasingly negative public perceptions. Operators, required to collect these materials in pits and/or tanks, were faced with the question of disposal. Accepted practice was to dump the brines in a relatively unregulated manner, usually into shallow, often intermittent, alkali (sodium sulphate) waterbodies or sloughs near the production area. While there was no direct evidence of groundwater contamination (these sloughs are normally in groundwater-discharge areas) or of problems associated with overflows from the sloughs, concern grew on the part of government and industry that legal and environmental problems could be created. Continued unregulated disposal in this manner became unacceptable.

Few other options have been available for brine disposal. The Hatton area has had a lack of brine-injection wells within economic hauling distance. Besides cost, trucking damages rural roads constructed to relatively low standards and adversely affects unimproved trails in environmentally sensitive terrain. Surface spreading, even on a one-time basis, was never considered an acceptable alternative due to concern for groundwater and soil quality.

The Environmental Review Process

Saskatchewan Environment and Public Safety administers The Environmental Assessment Act, the legislative reference for the province's environmental-impact assessment (EIA) procedures (5). The EIA process can be divided into two functional components (4). The first step is the initial inter-agency review or screening of disclosure documents (project proposal) to identify environmental issues raised by the proposal and to determine whether a full-scale EIA is necessary. After obtaining what is in effect an "approval-in-principle" following the proposal review, proposals are referred to other provincial agencies to obtain specific licences or permits. If an EIA is required, however, the second part of the review procedure ensues, with preparation and review of the EIA and ultimately a decision on project acceptability.

Since initiation of the requirement for detailed, formal environmental reviews (screening) of brine-disposal proposals on January 1, 1989, some 30 proposed facilities have been reviewed (to July 1, 1990). These reviews are coordinated by the Department of Environment and Public Safety, but they involve all other provincial agencies with regulatory interests or other concerns. Those few proposals which were felt to be unacceptable at the conclusion of the proposal review were voluntarily modified or withdrawn by the proponents without attempting to obtain approval for the original proposal through a full-scale EIA review.

Once the environmental review is satisfactorily completed, and the proposed design and operation of the disposal facility considered environmentally acceptable, the principal approving agency becomes the Department of Energy and Mines. This provincial agency is directly responsible for most on-

lease hydrocarbon-development activities, including drilling, cleanups, waste disposal, spills, and abandonment. They inspect approved disposal sites during construction and operation, specify monitoring requirements, receive and review all monitoring data, and may require operational changes or site decommissioning and closure in the event of environmental problems or non-compliance with operating conditions. Additional regulatory requirements may relate to local zoning ordinances, approvals for drainage works, and agreements with the land owner/occupant.

Acceptable Options for Disposal/Storage

Current policy developed cooperatively by Saskatchewan Environment and Public Safety and Saskatchewan Energy and Mines, in consultation with other provincial agencies, recognizes three on-surface disposal/evaporation procedures as acceptable in principle for disposal of blow-down brines in southwestern Saskatchewan (3). Policy requires that all on-surface, brine-disposal or -storage facilities undergo a detailed, pre-construction environmental review. Proposals must be prepared by licensed engineers and/or hydrogeologists, and must demonstrate both horizontal and vertical fluid containment, based on some combination of natural and engineered features.

Policy now emphasizes waste management, as opposed to simply considering waste disposal, as a key consideration. Where available, deep-well disposal remains the preferred brine-disposal option from an environmental point of view.

The three basic brine-disposal options considered acceptable in principle are:

- Disposal for evaporation into confined areas of alkali sloughs. Approved sloughs will have confined drainage basins, groundwater discharge, and high-concentration surficial deposits of sodium sulphate (Na_2SO_4) and other salts due to long-term evaporation. Geochemistry of groundwater in these sloughs is commonly highly saline (TDS greater than 30 000 mg/L, dominated by sodium and sulphate) and unsuitable for domestic or livestock consumption or

irrigation. Alternate uses of these sloughs must also be considered;

- Disposal for evaporation into non-alkali depressions lacking shallow groundwater and underlain by ≥ 5 m of low-permeability clays; and

- Disposal for storage/evaporation into double-lined, engineered ponds, with between-liner monitoring.

At each of these facility types, secure fencing and piezometers with prescribed monitoring protocols are required.

The balance of this paper outlines in some detail the basic design requirements and information which must be submitted by the developer for environmental review of each type of surface storage/disposal/evaporation facility.

Alkali Sloughs

The following requirements pertain to direct dumping of blow-down brines into unlined, alkali sloughs:

i) a qualified hydrogeologist shall document groundwater level and determine whether the location is in a groundwater recharge or discharge zone. Unlined disposal sites in slough areas will be permitted only in clearly defined groundwater-discharge zones;

ii) report groundwater quality at disposal site;

iii) report quality of ponded surface water (if present);

iv) perform testhole logs using standard procedures to describe soil characteristics to a minimum 10-m depth;

v) a qualified hydrologist shall describe hydrology of the slough and surrounding drainage basin:

   - estimated effective and gross drainage areas of the slough and a plan illustrating these areas;

- anticipated runoff volumes (mean and 1-in-25-year extreme events) into the slough;

- estimated slough spill (overflow) frequency with and without dumping additional material. A multi-year simulation of fluid levels incorporating wet years is advisable. Indicate downstream implications of slough spillage;

- estimated annual gross and net evaporation (mean and 1-in-25-year extreme events), and derivation of these estimates explained. Include allowance for excessive precipitation, below-normal evaporation, and salinity effects on evaporation rates;

vi) describe and evaluate any proposed hydrologic isolation of the proposed disposal area (e.g., dykes), and estimate storage volume of the isolated area. Size of the area which may be used should be minimized. Will isolation measures affect existing water levels, run-off patterns, and nearby lands?

vii) include a statement from appropriate licensed professional(s) that the facility is capable of receiving annually a specific maximum volume of wastes and isolating these wastes so as to prevent both vertical and horizontal migration. Waste containment and isolation must be based on demonstration of all of the following:

- hydrologic isolation - dykes, landforms, localized extent of the slough;

- horizontal isolation - absence of permeable zone at or near surface;

- vertical isolation - groundwater discharge zone;

- a calculated net annual evaporation potential on average in excess of the proposed fluid disposal volumes plus estimated natural water inflows;

viii) include other relevant information, such as:

- detailed chemical characterization of wastes;

- locations of surface and groundwater users and water quality in dugouts, wells, impoundments, lakes or streams within 1 km;

- monitoring program for leakage detection. Piezometers installed according to conventional protocols and to an appropriate depth are to be located on each side of the slough. Submit twice-yearly tests of piezometers and monitoring, or more frequently as may be required;

- describe other actual or potential beneficial uses of the proposed location - e.g., wildlife, particularly waterfowl. Describe vegetation;

- contingency plans for flooding, lack of evaporation, leaking, and major spills;

- evidence of landowner/occupant and local government approval/consent;

- fencing and gating to prevent public, livestock and wildlife access;

- facilities for fluid dumping and access;

- decommissioning plans, including potential need for remediation and/or disposal of salt-contaminated soils. The proponent must explicitly accept responsibility for all reclamation and disposal requirements at the time of decommissioning.

Non-alkali Depressions

Requirements pertaining to direct dumping of blow-down brines into shallow, unlined, non-alkali depressions (e.g., topographic lows, kettle sloughs) are similar to those which apply to alkali sloughs. The points which follow represent the differences in information and design requirements for disposal into non-alkali depressions. Requirements numbered

ii), iii), v), vi), and viii) for Alkali Sloughs (above), and pertaining to the following topics, are common to non-alkali depressions: groundwater quality and production potential, quality of any ponded surface water, basic hydrology data (including estimated capacity of the depression), methods of hydrologic isolation, nearby water users and water quality data, monitoring programs, waste characterization, other potential uses of the location, contingency plans, appropriate approvals/consents, ancillary design details (fencing, gating, access), and decommissioning plans. Additional information includes:

i) this practice is NOT a preferred option, and any such proposal MUST be accompanied by an explanation of why alternate methods/locations are not proposed;

ii) a qualified hydrogeologist shall document groundwater level and determine whether the location is in a groundwater recharge or discharge zone. Disposal into shallow, unlined, non-alkali depressions may be permitted only in areas adequately underlain by low-permeability natural materials;

iii) perform a minimum of four testhole logs using standard procedures to describe soil characteristics to a minimum 10-m depth. Determine soil permeability;

iv) include a statement from appropriate licensed professional(s) that the facility is capable of receiving annually a specific maximum volume of wastes and isolating these wastes so as to prevent both vertical and horizontal migration. Waste containment and isolation must be based on demonstration of all of the following:

- hydrologic isolation - dykes, landforms, localized extent of the basin;

- vertical isolation - low-permeability clay or other similar material (in the range of 1×10^{-7} cm/sec or lower in situ, after salt-saturation effects on the soil) to a depth of at least 5 m below the base of the disposal location;

- horizontal isolation - presence of low-permeability zones at surface and at depth. There must be a demonstrated absence of interbedded, high-permeability materials (e.g., sand, gravel) within the required 5-m low-permeability zone forming the sides of and underlying the disposal location;

- a calculated net annual evaporation potential on average in excess of proposed fluid disposal volumes plus estimated natural water inflows.

Lined Evaporation Ponds

The following requirements pertain to proposals for lined storage/evaporation ponds. Lined ponds are required wherever brine containment cannot be guaranteed based on soil type, hydrodynamics (groundwater discharge) and landform.

i) document groundwater level and quality;

ii) report quality of any ponded surface water;

iii) perform testhole logs using standard procedures to describe soil characteristics to a minimum 5-m depth below projected pond base;

iv) provide detailed design for lined ponds, including a statement of design life. A double-lined system incorporating a sump and monitoring between the two liners normally is required. How will fluids be dumped into the pond? A minimum 0.3-m freeboard is required;

v) include liner specifications and ability to withstand anticipated stressors (e.g., cold, flexing, chemicals, UV, IR, and freeze-thaw and wet-dry);

vi) include incidental design elements such as surface diversions to exclude runoff, fencing, and rope ladders to assist emergency escape;

vii) evaluate the pond's annual gross and net evaporative potential and explain derivation of these estimates.

Precipitation, run-off (from dykes), drifted snow, and evaporative potential for mean and 1-in-25-year extremes are to be considered. Anticipated evaporation rates should include allowance for excessive precipitation, below-normal evaporation, and salinity effects on evaporation rates. Where will excess (non-evaporated) fluids be disposed? Clean-out and disposal of accumulated solids should be discussed;

viii) include a statement from appropriate licensed professional(s) that the facility is capable of receiving annually a specific maximum volume of wastes and isolating these wastes so as to prevent both vertical and horizontal migration;

ix) include a variety of other relevant information, as outlined in point viii) under Alkali Sloughs, above.

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3. Saskatchewan Environment and Public Safety, Saskatchewan Energy and Mines, Policy Statement: Handling of Blow-Down Brines and Salt-Based Drilling Mud Systems, Regina, 1990

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Acknowledgements

Larry Kratt, former Director of Environmental Assessment, Saskatchewan Environment and Public Safety, and Jerry Gossard, Director of Petroleum Development, Saskatchewan Energy and Mines, kindly reviewed a draft of this paper.

Table 1: Summary of Blow-Down Water Quality, as reported by Hanley (1989)

Concentration in mg/L - pool or zone[1]

Constituent	Medicine Hat	Second White Specks	Milk River
Total Hardness (as $CaCO_3$)	276	287	83
Total Alkalinity	611	1,161	636
Salinity as NaCl	11,852	10,896	6,058
Sodium (Na)	4,440	4,140	2,400
Potassium (K)	59.0	224	45.4
Calcium (Ca)	48.4	42.2	12.6
Magnesium (Mg)	37.2	39.8	12.5
Iron (Fe)	1.41	10.3	0.205
Chlorine (Cl)	6,550	6,020	3,340
Fluorine (F)	0.37	0.16	0.13
Bicarbonate (HCO_3)	745	1,390	776
Carbonate (CO_3)	0.00	12.6	0.00
Sulphate (SO_4)	37.4	<10.0	<10.0
pH	7.60	8.12	8.03
Total Dissolved Solids, TDS	11,919	11,870	6,587

1. Except pH

ENVIRONMENTAL CONSEQUENCES OF MISMANAGEMENT OF WASTES FROM OIL AND GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION

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Over the past several years, EPA has been investigating the environmental impacts caused by oil and gas operations in most producing regions of the United States. Much of this research was conducted for our 1987 Report to Congress on exploration, development, and production wastes required by RCRA--the Resource Conservation and Recovery Act.

That report and the public comments we received led to EPA's regulatory determination that oil and gas wastes from exploration, development, and production should remain excluded from RCRA's hazardous waste management requirements. In making this determination, the Agency recognized that improvements in waste management were needed at least in some instances. As a result, EPA and the States are now developing strategies for improving oil and gas waste management under RCRA's provisions for managing *non*hazardous wastes--that is, under Subtitle D of RCRA. This authority offers the kind of flexibility and region-specific responsiveness that the States and industry need. From our point of view, it can also provide the benchmarks needed to improve the standards and bring about consistency in the way certain wastes are managed from area to area.

This paper illustrates the kinds of problems that need to be addressed. More important, it shows that most of these problems have proven solutions. We have concluded that, although adverse impacts can result from improper oil and gas waste management, those impacts can often be minimized through improved housekeeping practices and use of existing technologies.

The pictures in this paper are all recent--no earlier than 1987--with most being taken in 1988. There are some problem areas, such as the management of reserve pits on the Alaska North Slope, that I touch on only lightly because significant progress has been made since we started our research for the 1987 Report to Congress.

Let's start with disposal of produced water. Produced water is the highest volume waste stream generated by production activities and has historically been responsible for some adverse environmental impacts associated with this industry. Some 20 billion barrels of produced water were generated in 1985, according to the estimates used in the 1987 Report to Congress. It is estimated that most of this produced water (roughly 80 percent) is reinjected into Class II wells. A small percentage, however, is managed onsite in unlined pits or is discharged to surface water.

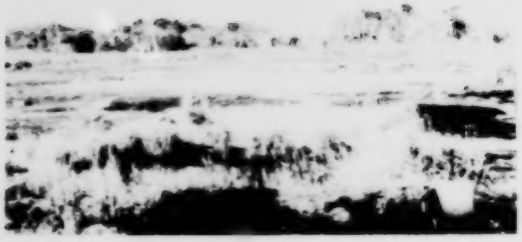

Figure 1. Louisiana, May 1988

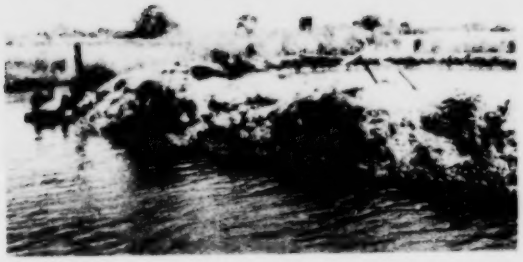

Figure 2. Louisiana, May 1988.

Figure 1 shows the impact of discharges of produced waters to freshwater wetlands in the Gulf Coast region. Vegetation damages caused by the release of saline produced waters are clearly visible in the center of the area shown. This discharge occurred without the required permit.

Figure 2 shows an unlined produced water skim pit used to skim oil from produced water prior to discharge to a river in a protected freshwater wetlands area. This pit was constructed out of porous native peat allowing for the potential of seepage of pit contents into the surrounding area. Produced water in this pit may contain benzene, heavy metals, and radioactivity.

Figure 3 is another example of how disposal of some produced water in unlined onsite pits can lead to adverse environmental impacts. Using such pits to manage produced water may lead to ground-water contamination, surface water contamination, and vegetation damage. (Of course, some produced waters may be suitable for beneficial use, such as irrigation.)

Figure 4. Arkansas, March 1988

Figure 5. West Virginia, February 1988

Figure 4 shows the results of long term discharges of produced waters to a forested area in the south. The environmental impact of this practice is apparent. All vegetation is absent in the area receiving the discharge. Although the source of the acute damage from produced water is chlorides, EPA remains concerned about other potential constituents of produced water, such as metals, benzene, and radioactivity. Additional information is needed about the presence of these constituents in produced water and their resulting impacts on the environment.

Figure 5 shows a reserve pit that is located on a steep hillside above a residential community. The pit was partially lined with a plastic liner. Fluids from reserve pits like this have the potential to run off-site, potentially contaminating ground water and surface water. This pit, in fact, did breach, discharging produced waters down the hillside.

Figure 6. Arkansas, March 1988

Figure 6 shows another example of produced water disposal. In this area, dozens of stripper wells discharge produced water directly onto the surface of the land. The area shown in the photograph has been denuded of vegetation. The practice has been allowed for many years and may lead to adverse environmental impacts.

Currently, management of produced water--through use of pits (particularly unlined pits) or discharge to streams, wetlands, or other bodies of water--

poses threats to the environment at many sites. The solution includes better housekeeping practices and use of reinjection in Class II wells either onsite or at properly designed and maintained centralized or commercial facilities. The operable word here is "proper." We have seen many cases where improper management of produced water has led to adverse environmental impacts.

To illustrate, let me turn to injection facilities, which handle the bulk of produced water disposal. Injection of produced water and other aqueous waste in properly designed and maintained injection wells provides a desirable method for managing such wastes; however, surface facilities (tanks, pits) associated with injection facilities can pose RCRA-related problems.

Figure 7. Arkansas, March 1988

Figure 8. Utah, March 1988

Figure 7, for instance, illustrates a centralized Class II injection facility that operates a holding pit in conjunction with the injection well. The facility accepts many types of oilfield wastes, including tank bottoms and produced water. The pit shown here is unlined and has been in operation for some time. Housekeeping is poor.

Figure 8 shows another Class II facility. At this facility, this unlined pit is referred to as an emergency overflow pit, but the buildup of oil around the edge of the pit indicates that "emergencies" may be fairly common.

Figure 9. Texas, March 1988

Figure 10. Arkansas, March 1988

Figure 9 illustrates an example of proper management of produced water. At this commercial Class II injection facility, the pits are lined with 100-mil polyethylene lining, and the site also has ground-water monitoring. Although this slide doesn't show much besides the lined pit, the appearance of the site indicates good housekeeping practices where healthy-looking vegetation is located quite near the pit.

In contrast, this Class II injection facility (Fig. 10) accepts tank bottoms, produced water, and many other oilfield wastes. The unloading hose shown here spills wastes onto the ground and into a nearby ditch.

Figure 11. California, May 1988

Figure 12. California, May 1988

Figure 11 shows a facility where, among a number of desirable features, the unloading hose is provided with its own containment sump. Site operators perform onsite waste characterization prior to accepting any waste, and have equipped tanks with high level alarms and automatic shutoff valves. This

picture also illustrates sound housekeeping practices. This is another shot of the same site (Fig. 12).

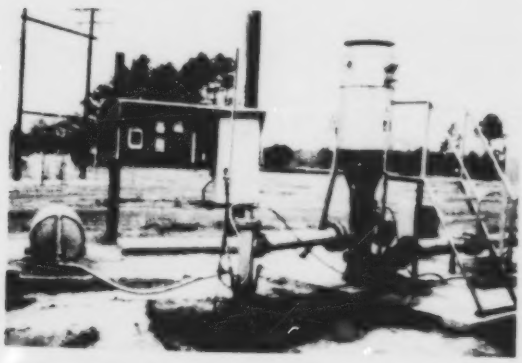

Figure 13. Texas, March 1988

Figure 14. California, April 1988

Figure 13 illustrates another example of sound oilfield waste management at a commercial disposal facility. This is a Class II injection well, equipped with automatic injection of corrosion inhibitor into the annulus, continuous pressure monitoring, automatic shutoff valves, and ground-water monitoring. It provides another example of sound waste management practices.

Let me now go on to other types of centralized or commercial facilities that manage produced water and other oilfield wastes. While alternative means of produced water disposal, such as through evaporation in open centralized or commercial pits, may be effective in the more arid regions of the country, minimizing adverse environmental impact depends largely upon the design, maintenance, and overall housekeeping practices of a facility.

Figure 14 shows an example of a poorly designed and maintained unlined ditch used by a conglomerate of operators in California. Produced water is discharged to this unlined ditch that leads to centralized disposal pits. Over the years, ground water in the area has been contaminated with high levels of chlorides and other salts associated with produced water, rendering the ground water unsuitable for drinking purposes.

Figure 15. Louisiana, April 1988

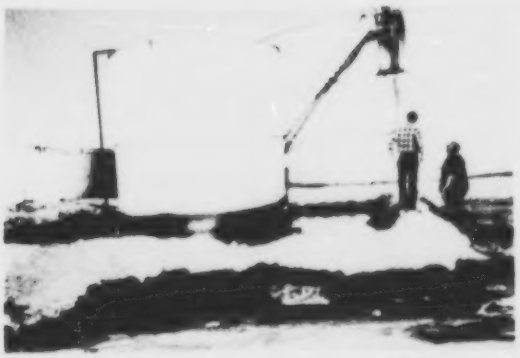

Figure 16. Louisiana, May 1988

Figure 15 shows a commercial landfarm operation in Louisiana. It accepts all types of oilfield wastes, not just produced water. At this site, trucks wash out the residue in their tanks directly into ditches. These in turn discharge into an adjacent stream.

Storage tanks can also be a problem at commercial facilities. This commercial oilfield disposal facility (Figure 16) accepted all types of oilfield wastes. In this case, oily waste from one of the storage tanks is leaking through the earthen berm that is supposed to contain any spills from the tank. The land surrounding the units shows signs of contamination from spills and leaks. [NOTE: the facility is now closed by order of the State.]

Figure 17. Louisiana, May 1988

Figure 18. Louisiana, March 1988

Figure 17 is another photograph of the same commercial facility, this time showing its produced water discharges. The saline produced water was being discharged directly to a nearby freshwater stream.

This photo (Fig. 18) is taken at an abandoned crude oil reclaimer facility located directly adjacent to the Intercoastal Waterway on the Gulf Coast. Notice the oily berm surrounding the impoundment. One of the problems associated with some commercial facilities is the absence of State remediation or reclamation requirements.

Figure 19. Louisiana, April 1988

Here's another photo taken at an abandoned commercial treatment and disposal facility in the Gulfcoast area (Fig. 19). This one has been proposed for the CERCLA National Priority List for cleanup under the Superfund program. The site accepted many wastes associated with oilfield operations, such as fracing fluids, emulsifiers, mud additives, biocides, and workover fluids, some of which may not have been suitable for management through land treatment and disposal.

Onsite pits are commonly used to handle categories of oil and gas wastes other than produced water, including drilling muds and associated oilfield wastes. Let me now discuss a few issues raised by these multipurpose pits.

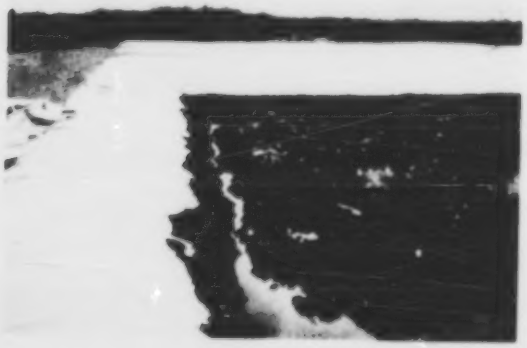

Figure 20. Alaska, June 1988.

Figure 21. New Mexico, March 1988

This picture (Fig. 20) shows well-designed pits used for oily waste disposal. Note the heavy lining and the fence surrounding the site. This pit was about to be closed but apparently is in good condition even at the end of its operating life.

The opposite type of situation is shown in Figure 21. This site accepts all types of wastes, with no characterization prior to disposal. Hydrocarbon odors were very strong when this site was visited in March 1988.

Figure 22. Texas, September 1988

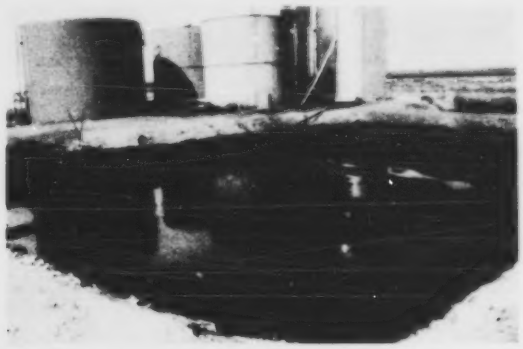

Figure 23. Texas, September 1989

So far, I've discussed design problems, operational problems, the mixture of associated wastes with produced water, closure problems, remediation problems, wetlands impacts, and surface water contamination. But oil and gas operations can also pose threats to wildlife. The next group of photographs was provided by the U.S. Fish and Wildlife Service. This aerial shot shows extensive oil production in the Southwest (Fig. 22). From this bird's-eye perspective, it is clear that in areas where development is this intense, there's a significant likelihood that some birds looking for water will land on oilfield waste pits and tanks.

Figure 23 shows a typical open sludge pit within such an area. Note that it's unlined. The point of the picture, however, is that it is also uncovered, offering no barrier to birds that might enter it.

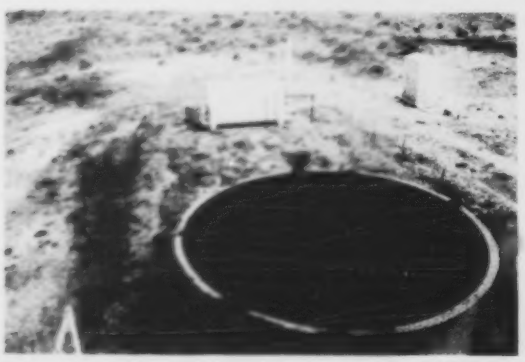

Figure 24. Texas, September 1989

Figure 25. Texas, September 1989

Similarly, this (Fig. 24) is a typical open-topped storage tank in the same general area of the country. Note that it too is uncovered.

This photo (Fig. 25), taken in the Southwest in 1989, shows dead birds in an open produced water tank.

Figure 26. Texas, September 1989

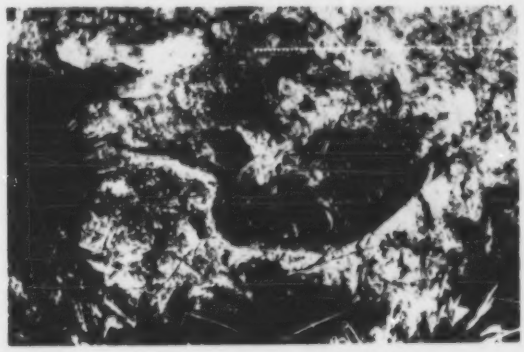

Figure 27. Texas, September 1989

Here (Fig. 26) migrating ducks died in an uncovered pit in 1989. The majority of pits that pose problems like this are sump pits that were constructed in the 1940s and 1950s, but are still in use in certain states.

Figure 27 shows a duck carcass at an oil sludge pit. Estimates vary on how many birds are destroyed each year by entering oilfield waste pits and tanks. A U.S. Fish and Wildlife study suggests that at least 500,000 animals, mostly waterfowl and migratory birds, were killed annually from the 1950s to the early 1980s.

Figure 28. Texas, September 1989

This is a Sandhill crane carcass taken from a sludge pit in 1989 (Fig. 28).

Figure 29. Texas, September 1989

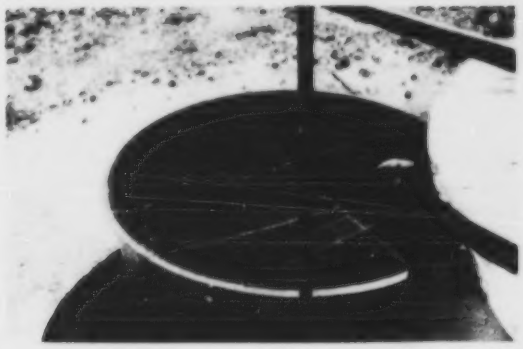

Figure 30. Texas, September 1989

The solution to this problem is to cover the pits and tanks with mesh to prevent animals from entering. New Mexico has recently enacted regulations requiring such covering, and Oklahoma has developed guidelines suggesting use of the same approach. Here is a sludge pit (Fig. 29) that has been effectively covered with wire mesh.

The same technique works for tanks (Fig. 30).

One category of wastes with which EPA is particularly concerned is the broad catch-all of "associated wastes" that I've already alluded to. These include various wastes that pose special problems because of their often relatively high toxicity compared to produced water and conventional water-based drilling fluids. What follows are some examples of associated waste management practices that may lead to adverse environmental impacts.

Figure 31. Texas, September 1989

Figure 32. Utah, March 1988

At this site (Fig. 31), still bottoms from a tank bottom hydrocarbon recovery process are dumped onto an unlined vacant lot adjacent to the facility.

This is another site (Fig. 32) where tank bottoms are dumped with no lining, cover, or ground-water monitoring.

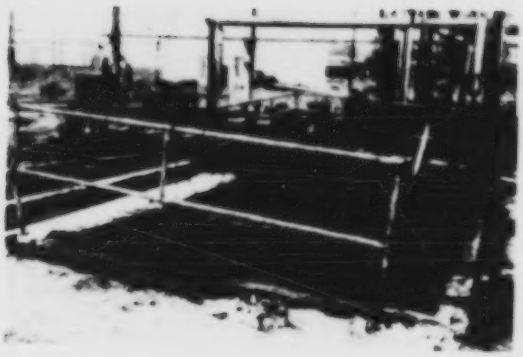

Figure 33. Texas, March 1988

Figure 34. West Virginia, February 1988

Figure 33 shows a tank bottom hydrocarbon recovery operation using below grade concrete pits for storage of oily sludges. No leak detection or monitoring is provided.

This photograph (Fig. 34) shows potential problems resulting from improper storage or disposal of drums containing solvents, corrosion inhibitors, and biocides. Leakage from the drums into a nearby freshwater stream poses risk of surface contamination. This type of problem can be directly addressed by proper disposal of used containers.

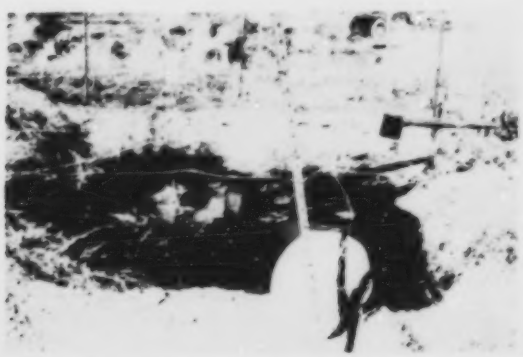

Figure 35. New Mexico, March 1988

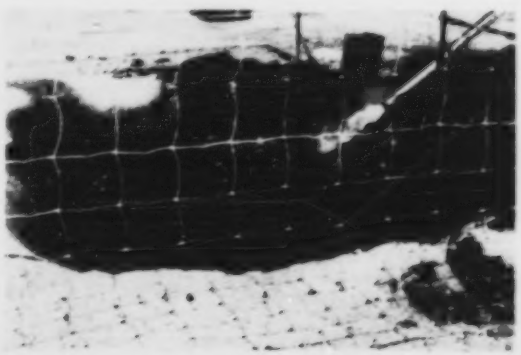

Figure 36. Utah, March 1988

Unlined produced water pits are banned in certain areas of some States because of high soil permeability and relatively shallow unconfined ground water. However, unlined drip pits such as this (Fig 35) are still allowed by some States if the units involved have low production rates. Despite the low

production rates, there can still be a potential for environmental impacts in some areas.

This photograph (Fig. 36) shows oily heater treater exhaust being discharged to an unlined pit in one of the western States.

The last group of slides I want to present today are from Alaska. As you are all aware, development in Alaska, both on the Kenai peninsula and on the North Slope, poses several unique problems--unique in terms of production and unique in terms of environmental protection. One of the most important current issues is lack of adequate capacity for offsite waste management.

Figure 37. Alaska, June 1988

Figure 38. Alaska, June 1988

As I mentioned earlier, strides have been made in the last several years in improving operation and maintenance of North Slope reserve pits. Problems like these are becoming less common. This illustration (Fig. 37) shows leakage of oily waste from a reserve pit, with a tundra kill in the surrounding area.

Here is a photograph (Fig. 38) of an unreported spill from one of the service company pads on the North Slope. The tundra mat was saturated with what appeared to be diesel fuel. This spill resulted in issuance of a Notice of Violation from the Alaska DEC, but some incidents such as this have gone undetected in the past because of the remoteness of the area and the difficulty of conducting most inspections during the brief summer months.

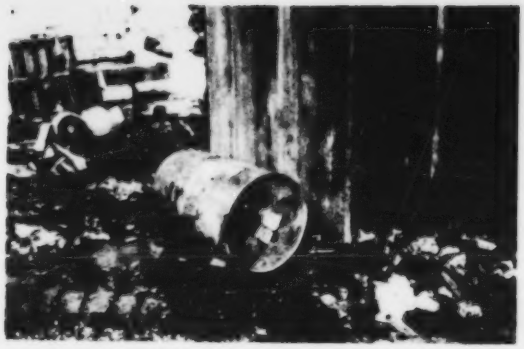

Figure 39. Alaska, June 1988

Figure 40. Alaska, June 1988

Given the improvements made in handling reserve pit wastes and spills, the problem that we at EPA are concerned about most is the general lack of capacity available for proper management of wastes generated by parties other than the major producers. This is a photograph (Fig. 39) of garbage piles, industrial wastes, and an incinerator in the service company area of Deadhorse on the North Slope. Note the drums and the array of garbage. Diesel fuel spillage was evident on the facility's pad.

This illustration (Fig. 40) shows how the landfill problem is beginning to overwhelm capacity to manage wastes. It's the North Slope Oxbow Municipal Landfill, which is divided into two sections--one for municipal wastes and one for industrial oilfield wastes. Capacity of the industrial segment, shown here, was initially projected to be adequate for 15 years, but it is now filled. The State has rejected the permit application for expanding the site, considering it technically inadequate.

It is becoming increasingly difficult to site properly managed facilities adequate to handle the demand posed by the continuing high volume of wastes generated by Alaskan production. However, some operators are investigating the possibility of constructing large new waste management facilities on the north slope.

* * *

The illustrations above demonstrate a few critical points. First, adverse impacts resulting from mismanagement of oil and gas wastes are real, but their degree ranges from high to low. Although many States have made strides in recent years in putting better controls in place, we're still faced with leftover problems of past years, such as abandoned substandard sites of all types. In addition, we have yet to put adequate controls on such issues as protection of wildlife.

Finally, we have to plan for the future. When production increases, as it eventually will when current depressed oil prices rebound, we have to be prepared for the additional stresses this will place on the waste management system.

The good news is that oil and gas waste management problems can be handled using improved housekeeping practices and current technology. EPA is interested in exploring waste minimization and pollution prevention approaches to reducing waste generation at the source, but even without new approaches here, the technology exists to improve most oilfield sites. Onsite waste management remains a continuing problem, but it can be addressed by making better use of offsite facilities and offsite management techniques, improving offsite waste management techniques, or using closed circuit (e.g., tanks) onsite systems. These are some of the issues the Agency will be tackling in the coming months and years.

EVALUATION OF CONTAINERIZED SHRUB SEEDLINGS FOR BIOREMEDIATION OF OILWELL RESERVE PITS

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Abstract

Vegetation (secondary) succession is extremely slow on soils contaminated with soluble salts by petroleum exploration activities in arid and semiarid areas. Excessive salt accumulations interfere with seed germination and seedling establishment of most species used for revegetation. Establishment and growth of transplanted fourwing saltbush (Atriplex canescens) seedlings and rooted stem cuttings, and seedlings of oldman saltbush (Atriplex nummularia), winterfat (Ceratoides lanata), and prostrate kochia (Kochia prostrata) were evaluated on three saline-sodic (EC = 23 to 93 ds m^{-1}, ESP = 13 to 46%) oil well reserve pits over a 3-year period. Survival of fourwing saltbush seedlings from an accession not adapted to saline soils was only 32%, compared to $\geq$ 73% for seedlings or stem cuttings from an accession adapted to saline soil. Oldman saltbush suffered 100% mortality subsequent to sub-freezing temperatures during the first winter following planting. Survival of winterfat and prostrate kochia transplants was 61 and 48%, respectively, after 3 years, and growth of these species was acceptable on the saline-sodic soils. Selection of specific accessions of species adapted to the existing conditions of the site to be revegetated appeared most promising for revegetation under extremely harsh environmental conditions.

Introduction

Revegetation of oil and natural gas drilling locations in arid and semiarid areas is complicated by soil profile disturbance and contamination. On-site disposal of drilling fluids in shallow, earthen pits (reserve pits) usually results in formation of salt-affected soils (1), and many of these sites remain barren for decades. Artificial revegetation is often necessary to stabilize critical areas and to attain an acceptable level of productivity.

Several shrub species are well adapted to drought and saline soils because of structural or physiological adaptations of roots and foliage (2, 3). Fourwing saltbush (Atriplex canescens) has been used successfully for revegetation of disturbed, salt-affected soils in the southwestern United States (4, 1). However, many other native and introduced species from regions with similar soil and climatological characteristics warrant evaluation to identify plant materials suitable for revegetation of severely disturbed areas.

This paper reports results from a 3-year study in which the potential of seedlings and/or stem cuttings of 4 shrub species for revegetating disturbed, saline-sodic soils was evaluated.

Materials and Methods

The study site was near Big Lake in Reagan County, Texas (31°15'N 101°40'W). The climate is semiarid, with hot summers and cold, dry winters. Average annual precipitation is 414 mm and about 78% of the precipitation is received from May to October. Estimated mean annual lake (free water) evaporation is 1800 mm (5). The average daily maximum temperature in July is 35.5° C and the average frost-free period is 229 days. The soil is a Reagan silty clay loam (fine-silty, mixed, thermic family of *Ustollic calciorthids*). The Reagan series consists of deep upland soils formed in calcareous, loamy sediment of ancient outwash and aeolian origin.

Field plantings were established on three oil well reserve pits in 1984 to evaluate establishment and growth potentials of: 1) fourwing saltbush seedlings grown from seed harvested from a native population on a moderately saline soil (EC $\geq$15 ds m^{-1}) 27 km west of the study area, near Texon; 2) fourwing saltbush stem cuttings taken from Texon plants which had successfully established on highly saline (EC = 71 to 114 ds m^{-1}) reserve pits (1); 3) fourwing saltbush seedlings grown from seed harvested from a native population on a non-saline (EC $\leq$4 ds m^{-1}) soil approximately 145 km southwest of the study area, near Bakersfield; 4) oldman saltbush (Atriplex nummularia) seedlings grown from seed produced in Australia; 5) winterfat (Ceratoides lanata) seedlings grown from seed harvested from native populations near Los Lunas, New Mexico; and 6) prostrate kochia (Kochia prostrata) seedlings grown from seed harvested in Utah.

Seedlings were grown in a greenhouse in 4- by 5- by 18-cm polyethylene tube packs in a 2:1:1 (v:v:v) peat moss/vermiculite/soil mixture and were 7 months old at planting. Stem cuttings were propagated in a greenhouse using an automatically regulated misting system.

Plots were established on reserve pits of three adjacent oil wells (0.5 km apart) drilled in 1983-84. The drilling fluids had been allowed to dry, then the pits were closed by the conventional method of mixing the dried drilling wastes with the soil from the pit borders. Each reserve pit was disked twice and fenced to exclude cattle and sheep. Field plantings were established on 21 September 1984. Seedlings were planted on 1.8-m centers in rows 2 m apart

(16 seedlings per row) using a Whitfield Model 57-DS-12 transplanter mounted on a 30-kw farm tractor. Each reserve pit planting was arranged as a randomized complete block design with three replications (rows) of each plant material.

Five soil cores were taken with a bucket auger to 45-cm depths at equidistantly spaced intervals on the diagonal of each reserve pit and separated into 15-cm increments for determination of electrical conductivity (EC) of the saturated paste extract and exchangeable sodium percentage (ESP) (6). Each site was sprinkler irrigated with 51 mm of water of low salinity (EC = 2 ds m^{-1}) immediately after planting. Seedling survival was determined 2, 12 and 36 months after planting by counting the number of live plants in each row. Shrub heights and canopy diameters were measured 12 and 36 months after planting.

Data for each sampling date from the three reserve pits were combined for statistical analyses following Bartlett's test for homogeneity of variance (7). Survival data were analyzed as a split plot where site was the main plot effect and plant material was the subplot effect. Prior to conducting analyses of variance, percentage data were transformed by $\sin^{-1}\sqrt{x}$. Means were separated using Duncan's multiple range test where appropriate ($P \leq 0.05$).

Results and Discussion

Average soluble salt concentrations in the surface 45 cm of soil ranged from 23 to 93 ds m^{-1} and ESP values ranged from 13 to 46% (data not shown). Soluble and exchangeable salt concentrations were sufficiently high for these sites to be classified as saline-sodic (6). Salt concentrations and ESP values were highly variable within each reserve pit, making it difficult to assess the "average" level of soil contamination.

Rainfall (130 mm) plus irrigation (51 mm) resulted in a total of 181 mm of water on the study sites prior to the 2-month evaluation (November 1984), which was about 168% of the long-term average for that time period. Annual precipitation received on the study sites during 1985, 1986 and through August 1987 was 92, 174 and 105% of the long-term average, respectively.

The site x plant material interaction was not significant for any of the three sampling dates. Thus, the main effects of site and plant material from the pooled analyses were evaluated within each sampling date. Plant survival at site A was significantly greater than survival at sites B or C after 2, 12 and 36 months (Table 1). However, overall plant survival on the more severely contaminated sites (B and C) tended to stabilize by 12 months after planting.

Average survival 2 months after planting ranged from 65% for Bakersfield fourwing saltbush seedlings to 92% for Texon fourwing saltbush stem cuttings (Table 2). Oldman saltbush seedlings exhibited strong establishment potential 2 months after transplanting (88% survival), but the seedlings died during

extended periods of low temperatures (<0° C) in December 1984 and January 1985. Similar winterkill of spring-planted oldman saltbush on non-saline soils in western Texas has been observed (D.N. Ueckert, unpublished data). Survival of Texon fourwing saltbush stem cuttings was significantly greater than that of the other plant materials except Texon fourwing saltbush seedlings 12 and 36 months after planting. Plant mortality between the 2- and 12-month evaluation dates (excluding oldman saltbush) ranged from 8 to 33%, but was ≤4% during the subsequent 24 months.

Differences in survival between the two fourwing saltbush accessions supported previous findings that germplasm from favorable environments is usually less adapted to harsh environments (8, 9). Bakersfield fourwing saltbush seed were obtained from an area more xeric than our study site, but the native population was on a non-saline soil. Fourwing saltbush seed from the Texon population germinated under lower (more negative) osmotic potentials than seed from native stands located further east or west of the study area (10). A further degree of selection may have been provided by the Texon stem cuttings taken from Texon seedlings that had survived and thrived on highly saline reserve pits. We hypothesized that the Texon stem cuttings would be more tolerant of the high levels of salt in the reserve pit soils. However, survival of the Texon stem cuttings was not significantly different from that of Texon seedlings.

Average shrub heights and canopy diameters 12 and 36 months after planting are presented in Table 3. The growth rates and growth forms of prostrate kochia and winterfat are inherently lower than that of fourwing saltbush, thus no statistical comparisons among species were made. Texon fourwing saltbush seedlings and stem cuttings grew more rapidly and produced more robust plants than the other species or Bakersfield fourwing saltbush seedlings 12 months after planting. However, Bakersfield fourwing saltbush surviving after 36 months had produced topgrowth comparable to that of Texon seedlings and stem cuttings. Prostrate kochia appeared more susceptible to feeding by insects and small herbivores than the other species, which may have partially contributed to its poorer growth. Fourwing saltbush, winterfat, and prostrate kochia produced seed in the second and third growing seasons, and seedlings of the three species where found adjacent to established plants after 36 months.

Conclusions

Transplanted seedlings and stem cuttings of a fourwing saltbush accession originating on saline soils near the study area showed the greatest establishment potential on saline-sodic oil well reserve pit soils in western Texas. These results supported previous laboratory and field studies which indicated that highly adapted accessions of some species may exist which are more suited for revegetation of extremely harsh sites (9, 10). Oldman saltbush appeared to be adapted to the saline-sodic soils; however, mortality of the seedlings the first winter suggested that the species lacks sufficient cold tolerance for the study area. Winterfat and prostrate kochia had lower survival percentages than fourwing saltbush but produced acceptable growth.

The use of shrub transplants may facilitate revegetation of severely contaminated rangeland soils where seed germination and seedling establishment may be poor. Further evaluation of germplasm from harsh soil and environmental conditions should greatly improve the potential for revegetation of salt-affected rangeland soils in arid and semiarid areas.

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TABLE 1

Average survival of transplanted shrub seedlings or stem cuttings 2, 12 and 36 months after transplanting on 21 September 1984 on oil well reserve pits as affected by site.

Site	Months after transplanting		
	2	12	36
	(%)		
A	77 a[1]	62 a	62 a
B	65 b	48 b	47 b
C	49 c	42 b	42 b

[1]Means within a sampling date followed by similar lower case letters are not significantly different ($P \leq 0.05$) according to Duncan's multiple range test.

TABLE 2

Average survival of transplanted shrub seedlings or stem cuttings 2, 12 and 36 months after transplanting on 21 September 1984 on oil well reserve pits.

Species/ plant material	Propagation method	Survival		
		2 months	12 months	36 months
		(%)		
oldman saltbush	seedlings	88 a[1]	--[2]	--
winterfat	seedlings	73 bc	65 b	61 bc
prostrate kochia	seedlings	72 bc	48 c	48 c
fourwing saltbush				
Bakersfield	seedlings	65 c	32 d	32 d
Texon	seedlings	86 ab	73 ab	73 ab
Texon	stem cuttings	92 a	80 a	77 a

[1]Means within a column followed by similar lower case letters are not significantly different ($P \leq 0.05$) according to Duncan's multiple range test.

[2]Indicates no survival because of winterkill.

TABLE 3

Average canopy heights and canopy diameters of transplanted shrub seedlings or stem cuttings 12 and 36 months after planting on 21 September 1984 on oil well reserve pits.

Species/ plant material	Propagation method	12 months		36 months	
		Height	Diameter	Height	Diameter
		(cm)			
winterfat	seedlings	30 ± 3	23 ± 2	59 ± 2	62 ± 4
prostrate kochia	seedlings	23 ± 3	25 ± 5	47 ± 2	68 ± 2
fourwing saltbush					
Bakersfield	seedlings	74 ± 7	74 ± 9	121 ± 5	233 ± 20
Texon	seedlings	99 ± 5	104 ± 8	117 ± 8	219 ± 11
Texon	stem cuttings	84 ± 14	99 ± 13	129 ± 3	231 ± 9

Mean ± standard error.

EVALUATION OF LIMITING CONSTITUENTS SUGGESTED FOR LAND DISPOSAL OF EXPLORATION AND PRODUCTION WASTES

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SECTION 1

Introduction and Summary

This document provides definition, technical justification, and applications guidance for salinity and petroleum hydrocarbon threshold values established for landspreading, on-site burial, or roadspreading of E&P wastes. Measurable parameters which serve as indices for proper management of salinity and petroleum hydrocarbons include: electrical conductivity (EC), sodium adsorption ratio (SAR), and exchangeable sodium percentage (ESP) for salinity; and oil & grease (O&G) for petroleum hydrocarbons.

The threshold guidance values generally recommended for land applied waste:soil mixtures are EC < 4 mmhos/cm, SAR < 12, ESP < 15%, and O&G < 1%. Index parameter thresholds have been developed to be generally applicable for any waste containing salts or petroleum hydrocarbons including E&P wastes under ordinary conditions.

Under certain restrictive conditions the generic guidance thresholds have to be adjusted or crops temporarily changed to more tolerant species. Depending on drainage, cover crop, and chemical treatment a soil with a loading no greater than that recommended should recover over a few seasons. The operator must determine whether the guidance values apply over the short- or long-term, or whether conditions warrant less restrictive values.

SECTION 2

Technical Justification and Literature Review

2.1 Limiting Constituents

Salts and hydrocarbons have been identified as the principal limiting constituents of concern relative to onshore E&P operations because they may induce a phytotoxicity or, in the case of sodium salts, may deteriorate soil structure interrupting normal soil-plant-water relationships and causing excessive erosion

(Miller and Honarvar, 1975; Ferrante, 1981; Freeman and Deuel, 1984; Nelson et al., 1984). Salts and hydrocarbons associated with E&P wastes may pose a significant threat to surface and groundwater resources when not properly managed (Henderson, 1983; Murphy and Kehew, 1984).

2.2 Salinity

Salinity is a general term reflecting the levels of available cations and anions in aqueous solution. Major ions include sodium (Na), calcium (Ca), magnesium (Mg), potassium (K), chloride (Cl), sulfate (SO_4), bicarbonate (HCO_3), carbonate (CO_3) and hydroxide (OH). EC reflects the ionic strength or total level of these constituents, while SAR and ESP consider the influence that specific ions may have under particular circumstances.

2.2.1 Definitions

Charged particles in solution will conduct an electric current to an extent determined primarily by the concentration and type of ionic species present, hence the term electrical conductivity. EC is measured directly in reciprocal units of resistance and conveniently reported in millimhos per centimeter (mmhos/cm). Since dissolved solids are predominately dissolved salts in the form of dissociated charged particles, EC may be used as an indirect, approximate measure of total dissolved solids (TDS).

TDS is defined in chemical terms as the unfilterable residue associated with aqueous fluids resulting from the evaporation of a known quantity of water, and is reported in terms of mass per unit volume (mg/liter). This residue is predominately composed of salts, but may include organic materials (humic substances or anthropogenic compounds) or mineral colloids passing through the filter.

An exact relationship exists between concentration of a specific salt in pure water and electrical conductance of that solution (Barrow, 1966). However, this relationship is inaccurate at high salt concentration, solutions of mixed salt species, or presence of nonionic dissolved species. Of more immediate use have been empirical correlations between TDS and EC for various aqueous solutions:

$$TDS = (A) \times (EC)$$

with the regression constant "A" (slope), being used as a conversion factor. Values of "A" have been found to range naturally from 540 to 960 cm.mg/mmhos.liter (Hem, 1985). For naturally occurring saline/sodic soils a constant of 640 may be assumed (USDA Handbook 60, 1954). Using the above equation, one calcu-

lates a TDS of 2560 mg/liter at a corresponding EC of 4 mmhos/cm, and "A" of 640 cm.mg/mmhos.liter. A recent analytical review of E&P wastes by the EPA (1987), and parallel review by the API (1987), suggested that an "A" value of 613 gives a better estimate of TDS in E&P wastes when calculated from EC.

TDS is generally not an accurate measure of salinity for many E&P wastes, due to errors associated with hydrocarbons and fine clay passing the filtration step. If one wants the perspective of salinity on a mass basis, it is best estimated from EC. EC has long been the parameter of choice in defining salinity hazards associated with production agriculture.

2.2.2 Concerns

Although some elements, such as boron, are toxic to plants, generally the ill effects of salinity are caused by increased osmotic pressure of soil solution in contact with plant roots (Haywood and Wadleigh, 1949; U.S. Salinity Laboratory Staff, 1954). Osmosis is a process that controls the movement of water between solutions and depends upon the number of dissolved molecules or ions (salinity). Water flows from lower to higher osmotic pressure. Plants have an osmotic pressure associated with their cell solution which varies greatly between plant species and to some degree between cultivars within species. If the osmotic pressure in soil solution outside the plant exceeds that inside, the plant wilts. The point of permanent wilting is reached when the plant can not recover even when exposed to less saline water. There is a direct relationship between osmotic pressure and EC:

Osmotic Pressure (OP), atm. = 0.36 X EC, mmhos/cm

Salts also effect plants by disrupting normal nutrient uptake and utilization (Kramer, 1969). The mechanism is one of simple antagonism, whereby a given salt specie in excess inhibits the plant uptake of required elements. The effect is usually manifested as a deficiency resulting in lowered yield expectations or overall crop quality.

There is no one critical or threshold salinity level where all plants fail to grow or maintain acceptable yields. General crop response to soil salinity is shown in Table 1 (U. S. Salinity Laboratory Staff, 1954). The sensitivities of various agricultural crops to salt are shown in Figures 1 through 3 (Maas, 1986). For example: at an EC of 4 mmhos/cm barley, cotton, and bermuda grass are not affected by salt, whereas, yields are expected to decrease for rice and corn (0-15%), alfalfa and sugarcane (15-30%) and beans (30-50%). Yield response intervals shown in Figures 1 through 3 were developed from agricultural systems receiving salt-containing irrigation water over the long

term and may overestimate the anticipated response for a one time land disposal of E&P wastes. Lunin (1967) suggests that irrigation water salinity guidelines developed for continual use systems can be doubled for a one time application. The rationale being that salt accumulated outside the bulk soil mass (in pores and on ped surfaces) is more easily displaced than that penetrated into and reacted with the bulk soil mass.

Table 1.
General Crop Response as a Function of EC.
(After U. S. Salinity Laboratory Staff, 1954)

EC (mmho/cm)	Affect on Crop Yield
0 - 2	None
2 - 4	Slight to none
4 - 8	Many crops affected
8 - 16	Only tolerant crops yield well
> 16	Only very tolerant crops yield well

If the salinity is initially too high for a given crop after land application of waste, soils will generally recover following rainfall or irrigation water containing less salt because excess salts are leached when adequate drainage is present. Growth of more salt tolerant plants may be desirable during the interim between application and recovery (Foth and Turk, 1972). Reclamation of salt-containing soils may be hastened through the application of calcium sulfate (gypsum) which results in the replacement of exchangeable sodium by calcium (Oster and Rhoades, 1984). Plants grown on gypsiferous soils will tolerate an EC approximately 2 mmho/cm higher than those shown in Figures 1 through 3 (Mass, 1986). This is because gypsum is dissolved at moisture equivalents used in preparing saturated soil extracts for analysis but not at moisture equivalents normal to field conditions.

USDA Handbook 60 (U.S. Salinity Laboratory Staff,1954) classifies water with EC values above 2.25 mmhos/cm as unfit for agricultural purposes except under very special circumstances. Soils with salinity levels > 4 mmhos/cm are considered saline. The recommended criteria of 4 mmhos/cm is too high for the more salt sensitive crops (Table 1.), and some adjustments may have to be made relative to intended land use. Miller and Pesaran (1980) found that high concentrations of soluble salts in mud-treated soil hindered plant growth in a 1:1 mud:soil mixture. Extracting their data where EC of the mud:soil mixture was < 8 mmho/cm, yield decreases averaged only 7% for green beans and 13% for

Fiber, Grain, and Special Crops

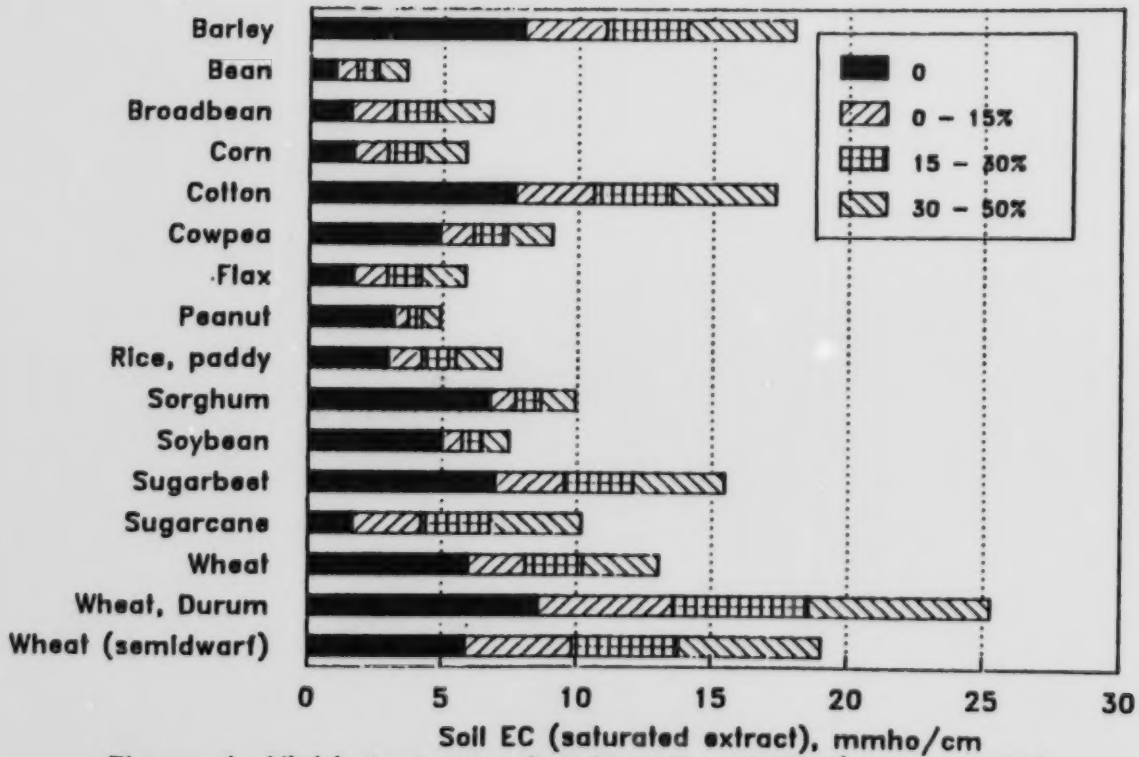

Figure 1. Yield decrease due to soil salinity (Maas, 1986)

Grasses and Forage Crops

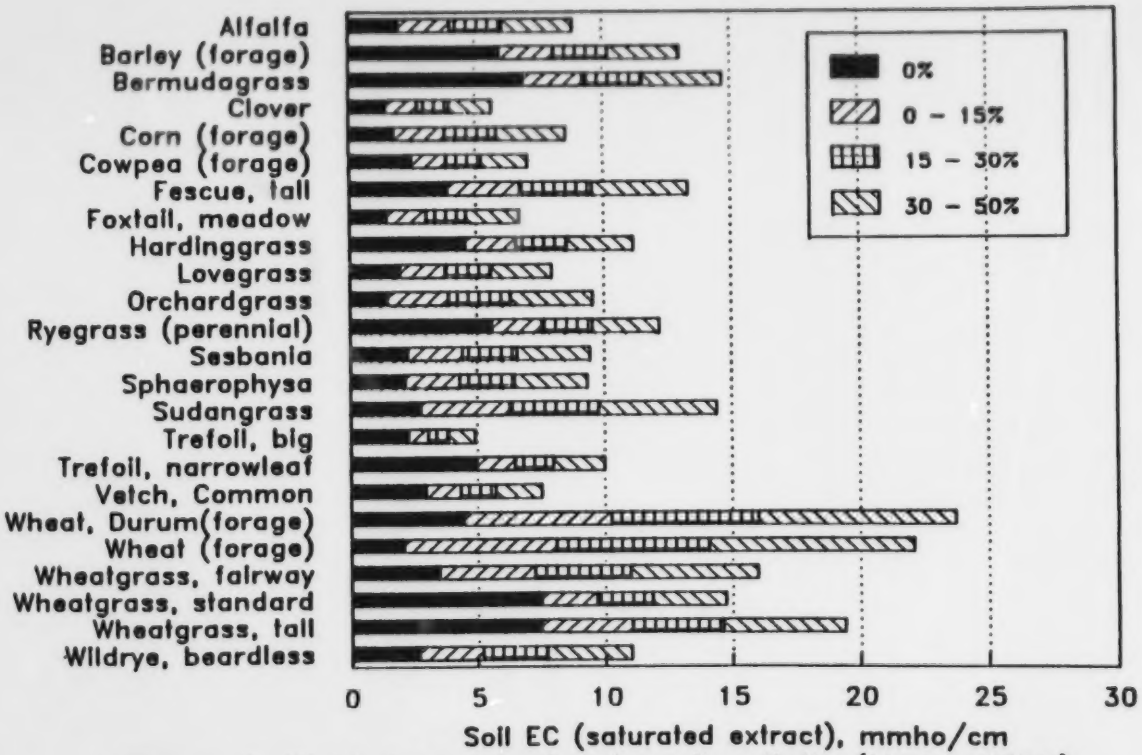

Figure 2. Yield decrease due to soil salinity (Maas, 1986)

Vegetable and Fruit Crops

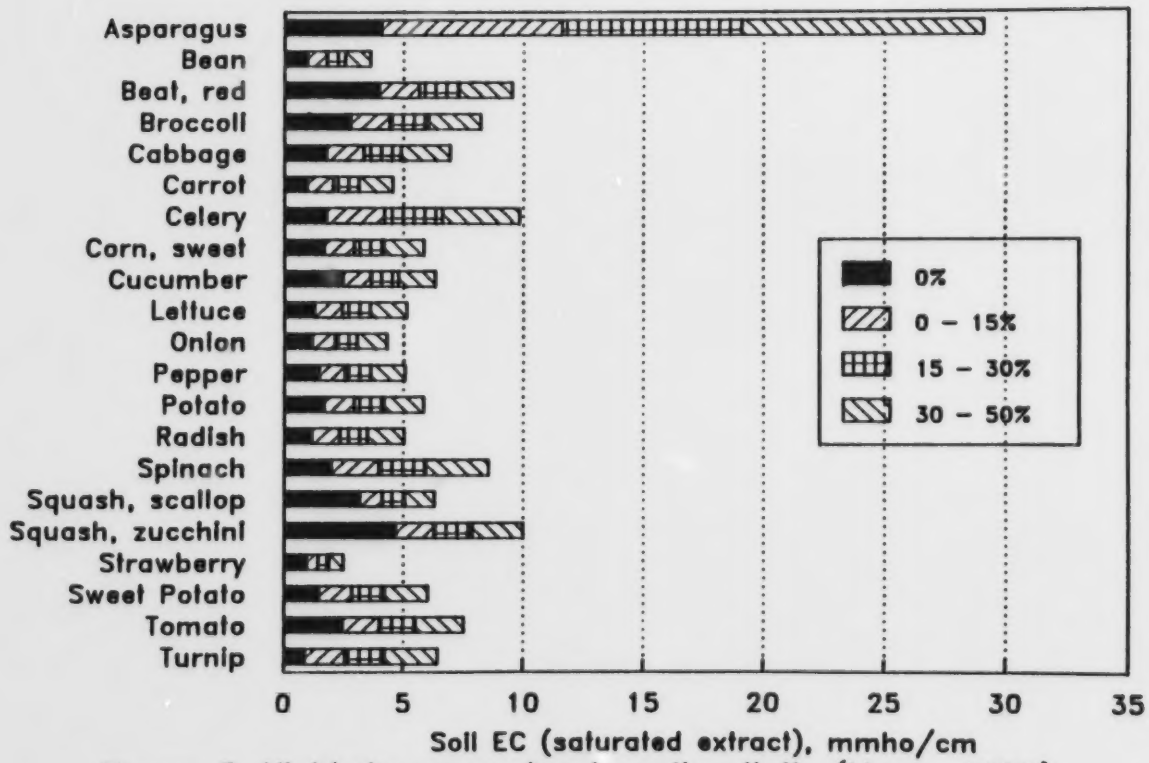

Figure 3. Yield decrease due to soil salinity (Maas, 1986)

sweet corn. Nelson et al. (1984) measured average yield decreases of 20% and 38% for swiss chard and rye-grass, where EC ranged from 6.3 to 18.6 mmho/cm. In these studies EC was above the recommended criteria of < 4 mmho/cm. Tucker (1985) reported adding drilling mud with resulting EC values from 1.3 to 5.3 mmho/cm with no adverse effect on bermudagrass and at 1.7 mmho/cm with no adverse effect on alfalfa. He also reported a significant decrease in EC with time following application, reflecting the leaching of salts out of the root zone.

It is apparent that a one-time EC application guideline of 4 mmho/cm is sufficient to limit yield decreases for most crops to < 15%. In those cases where precipitation, drainage, or crop type places special restrictions on waste management, some adjustments may have to be made relative to waste addition levels or intended land use while the soil recovers.

In areas of net infiltration, the soluble salts are transported from the surface to lower soil zones. Murphy and Kehew (1984) found that soluble salts from a pit containing saturated brine drilling fluids (EC > 200 mmhos/cm) posed a threat to localized ground water resources. It is obvious that an EC of 200 mmhos/cm greatly exceeds the recommended threshold of 4 mmhos/cm. Bates (1988), working with a fresh water drilling fluid, demonstrated that Cl was not retained in the zone of incorporation when mixed with surface soil.

The criteria of 4 mmhos/cm (2452 mg/liter TDS for "A" = 613) can be expected to have no measurable impact on groundwater even in the most sensitive hydrological settings. Water and associated dissolved constituents do not move through soils as an isolated unit (plug flow), instead there is a natural redistribution controlled by water potentials, pore dynamics, dispersion, and diffusion (i.e. chromatographic effect). Recent field research studies conducted by Owens et al. (1985) and Bruce et al. (1985) perhaps best illustrate this principal in that they were conducted at concentrations comparable in magnitude to the 4 mmhos/cm threshold. Both studies observed the redistribution of surface applied bromide (Br) by rainfall infiltration and percolation.

The Owens group demonstrated better than a 7 fold decrease in Br after passing through only 2.4 m of a well-drained silt loam soil due to attenuation processes mentioned above. Under conditions similar to their study, a surface loading of NaCl equivalent to 4 mmhos/cm (2452 mg/liter TDS) would result in an EC <0.6 mmhos/cm and corresponding Cl of < 213 mg/liter at a depth of 2.4 m. Bruce et al. (1985) showed Br redistribution from as great as 1800 mg/liter at the surface to <20 mg/liter below a depth of 3 m, after nearly 4 years and 4.7 m of rainfall. The Br level was 100 mg/liter at a depth of 1.5 m after 4 years with none detected below 3.8 m. If one substitutes Cl for the Br salts used in

these studies it becomes apparent that percolating water will be at or below the EPA drinking water quality standard of 250 mg/liter Cl (Part 143, 40 CFR, Sec. 143.3) within a few feet of the source at controlled land applications (EC < 4 mmhos/cm).

2.2.3 Criteria

In summary the EC criteria of 4 mmho/cm based on a one-time application serves to protect vegetation, land and groundwater resources at most drilling and production locations including those located in sensitive regions if amenable to a temporary adjustment in plant species. The criteria may be adjusted to meet special requirements.

2.3 Sodicity (ESP and SAR)

2.3.1 Definitions

The capacity of a soil to adsorb positively charged ions (cations) is called the cation exchange capacity (CEC) and may be expressed in meq/100 g. It follows that the exchangeable cations in a soil are those positively charged ions held on the surface exchange sites and in equilibrium with the soil solution. The major cations calcium (Ca), magnesium (Mg), sodium (Na), and K (potassium) are called basic cations and the percentage of the CEC occupied by these cations is called the base saturation. Fertile soils have a base saturation greater than 80% with the cations distributed mainly as Ca and Mg.

ESP is a measure of the degree to which the soil exchange sites are saturated with sodium and is calculated as follows:

$$ESP, \% = (NaX / CEC) \times 100$$

where NaX (exchangeable Na) and CEC are expressed in meq/100g. Ca and Mg are generally needed in relatively large amounts to maintain good soil structure (physical status relative to tilth and permeability) and fertility, but they form salts of low solubility in soils. Na salts are much more soluble and readily dominate soil solutions, often with a detrimental impact.

SAR is an empirical mathematical expression developed by the USDA Salinity Laboratory as an index to detrimental sodium effects in soils (U.S. Salinity Laboratory Staff, 1954). SAR is computed as follows:

$$SAR = Na / \sqrt{(Ca + Mg)/2}$$

where concentrations are expressed in meq/liter. Concentrations are determined by direct chemical analysis of pit liquids or aqueous extracts of waste solids or soils.

2.3.2 Concerns

High Na levels (SAR >12) in soil solution cause Ca and Mg deficiencies in plants by both antagonistic reactions and shifting of solubilities by common ion effect (Kramer, 1969; U.S. Salinity Laboratory Staff, 1954).
Soils reacted with solutions of high SAR are at risk of becoming sodic. A soil is termed sodic when the ESP exceeds 15% of the CEC (U.S. Salinity Laboratory Staff, 1954). The most distinguishing feature of sodic soils is their lack of structure and tendency to disperse in water. A dispersed soil condition has a devastating impact on plants by limiting the free exchange of air and infiltration of water (Reeve and Fireman, 1967; Bresler et al., 1983).

Research conducted by Tucker (1985) involving land disposal of waste drilling fluids confirmed that SAR < 15 and ESP < 15% are required for maintaining good soil structure and normal plant growth. Miller and Pesaran (1980) measured ESP for 1:1 and 1:4 mud:soil mixtures and found average yield decreases of 12% for green beans and 20% for sweet corn at an average ESP of 11.5%. The ESP in their study ranged from 0.6 - 19.7%.

SAR is somewhat less critical in that it represents the more easily altered solution phase. Deuel and Brown (1980) showed that the detrimental effect for water with an EC of 2.8 mmhos/cm and SAR of 16.1 was directly proportionate to the solid phase Ca in the receiving soil. The occurrence of appreciable amounts of gypsum in the soil, either naturally or by amendment may permit the disposal of highly sodic E&P wastes, particularly if the ionic strength of total salt is relatively low. Freeman and Deuel (1984) reported the successful pit closure (SAR < 15, ESP < 15%) by land disposal of E&P waste solids with SAR's > 200 and ESP's > 90, when salinities were < 4 mmho/cm. Treatment consisted of blending waste solids with native soils at chemically defined mix ratios in conjunction with gypsum and fertilizer amendments.

2.3.3 Criteria

Therefore, The API Environmental Guidance Document recommends an SAR of <12 and ESP of <15% for land disposal of E&P wastes. These values are widely accepted thresholds recommended by the USDA for preventing soil sodicity (U. S. Salinity Laboratory, 1954). Field and laboratory studies with drilling muds have also shown them to be reasonable values. It is important to note that guidance values pertain to final disposition or closure status: values do not limit the amount or composition of the wastes that can be land disposed. However, operators must be prepared to provide necessary management inputs for wastes applied to land in exceedance of recommended values.

2.4 Hydrocarbons

2.4.1 Composition and Analysis

Crude oil and diesel are the principal hydrocarbons associated with E&P wastes (Miller et al., 1980; Thoresen and Hinds, 1983; Whitfill and Boyd, 1987). They are sometimes added to water base drill systems to lubricate the drill bit and pipe string. O&G levels in freshwater drilling wastes are generally < 4% (Freeman and Deuel, 1986). Other E&P waste such as tank bottoms, emulsions, and oil-contaminated soil may have higher concentrations of O&G. A number of other hydrocarbons including asphalt, lignite, and lignosulfonates may be used in trace amounts during drilling operations (Honarvar, 1975; Miller et al., 1980) In general, the deeper the hole the greater the hydrocarbon level in mud formulations. Crude oil may also be incorporated into the drilling mud by contact with oil-bearing formations.

Crude oil and diesel fractions are comprised of a complex array of saturate and aromatic hydrocarbons (Thoresen and Hinds, 1983). Both fractions are readily partitioned from water by solvent using a separatory funnel or extracted from solid mineral components using a Soxhlet apparatus (Brown et al., 1983). Hydrocarbons extracted are assayed gravimetrically and reported collectively as oil and grease (O&G). Methylene chloride is the solvent of choice owing to its efficiency for extracting petroleum hydrocarbons without co-extracting significant quantities of naturally occurring organic matter (Brown and Deuel, 1983).

2.4.2 Concerns

A considerable amount of research has been carried out on the detrimental effects of crude oil and gas on plants and soils (Baldwin, 1922; Murphy, 1929; Schollenberger, 1930; Harper, 1939; Plice, 1948; Schwendinger, 1968; Garner, 1971; and Odu, 1972). The most phytotoxic compounds are lower molecular weight aromatic hydrocarbons, present initially, or formed as metabolites of the various degradation processes (Baker, 1970; Patrick, 1971; Thoresen and Hinds, 1983). Several studies (Murphy, 1929; Plice, 1948; Udo and Fayemi, 1975) reported marked inhibition of germination and corresponding yield reduction for row crops planted to soils receiving crude or waste oil applications in excess of 2% by weight. Pal and Overcash (1978) reported that the growth of vegetables and row crops were affected at an oil application of 1% by weight. Yields were generally 50% of control at 2% oil by weight. Bulman and Scroggins (1988) showed that plant growth was good on field plots with oil content of 3.5% or less but poor on plots with oil content of over 5%. At another site they found reduced crop growth in the first season after applying 1% and 2% oil in the soil. However, areas that received levels of 0.5% oil showed enhanced crop growth.

Frankenberger and Johanson (1982) reported certain crude oil components and refined petroleum products added to soil at 20% to 60% disrupt the oxidative and soil microflora activity requisite for biological assimilation following oil spillage events with oxidation being slowest for heavier molecules.

Miller et al. (1980) found that a 1% soil loading with diesel fuel resulted in decreased yields of 49% and 69% for beans and corn, respectively. Replanting after 4 months resulted in near normal growth. Younkin and Johnson (1980) grew reed canarygrass in soil initially containing 0.45% diesel fuel and found an initial germination decrease of 69%, a first harvest yield decrease of 79% and no yield decrease with a second harvest (75 days after diesel addition). Overcash (1979) determined an oil level of about 1% of soil weight as the threshold for reduced yields, and with 1.5 - 2% causing yield reductions greater than 50%. These effects occur immediately after application before hydrocarbon is assimilated by the various loss mechanisms. Table 2 lists the oil tolerance for selected crops (Overcash, 1979). Work by Ellis and Adams (1961) suggested that iron and manganese released under anaerobic conditions contribute to the phytotoxic response to soil contamination by petroleum hydrocarbons. Phytotoxic response was lowered after assimilation of the hydrocarbon by the soil.

Table 2.
Oil Tolerance for Selected Crops

Crop Type	Single Oil Application
yams, carrots, rape, lawngrasses, sugar beets	< 0.5% of soil weight
ryegrass, oat, barley, corn, wheat, beans, soybeans, tomato	< 1.5% of soil weight
red clover, peas, cotton. potato, sorghum	< 3.0% of soil weight
perennial grasses, coastal bermuda grass, trees, plantain	> 3.0% of soil weight

These studies indicate that under high hydrocarbon loadings (> 1%), E&P wastes may be detrimental toward plant growth. However, at 1% or less of mixed hydrocarbons, little or no yield reduction is expected based on existing information. Also, recovery of

the site is expected after a few months to one growing season, following a one-time application.

Several general observations of oil mobility in soil bear directly on any assessment of potential groundwater contamination. Plice (1948) observed that when oil enters the soil as a liquid, there is a natural segregation whereby the higher molecular weight, more viscous compounds are held near the surface while the lighter fractions penetrate deeper. Also, while the overall concentrations tend to decrease with depth, the composition towards the lighter end aromatic fraction tends to increase (Duffy et al., 1977; Weldon, 1978).

The recent review by EPA (1987) of E&P wastes showed only produced waters contained significant levels of the notably more mobile hydrocarbons including benzene, toluene, ethyl benzene, and xylenes (Roy and Griffin, 1985). These compounds were present in diesel oil-base drilling fluids but at concentrations that would be readily attenuated in subsurface strata by an adsorptive mechanism (El-Dib et al., 1978). Mobilities are also restricted by the chromatographic effect of liquids moving through a porous media (Waarden, Groenewoud, and Bridie, 1977). Oil floats, and its movement through soils is restricted to those pores of passable diameter, not saturated with water. Movement is further retarded by the "Jamin effect" or obstruction of a non-wetting fluid in a porous media (Schiegg, 1980).

At low levels of hydrocarbon addition to surface soils, leaching has not been found to be a problem. Watts et al. (1982) found no migration at a 30 to 45 cm depth after applying 14% industrial waste oil to the top 15 cm. Raymond et al. (1976) added about 2% oil to the top 15 cm and determined that 99% remained within the top 20 cm after 1 year. With loading rates of 3 and 13% of soil weight per year Streebin et al. (1985) found no significant oil migration below the zone of incorporation. Oudot et al. (1989) found the potential for leaching of unmodified hydrocarbons towards the groundwater was slight at a loading of 2% oil in soil. The one-time 1% level recommended for production waste additions to soil is therefore not expected to create any leaching problems.

2.4.3 Biodegradation

It has been demonstrated that soils have an adequately diverse microbial population and capacity to degrade E&P waste hydrocarbons (Raymond et al., 1967; Atlas and Bartha, 1972; Jobson et al., 1972; Kincannon, 1972; Westlake et al., 1974; Horowitz et al., 1975). Saturates and light end aromatics are degraded first, with kinetics or rate of degradation controlled by concentration and composition of hydrocarbons, nutritive status, aeration, moisture and temperature (Schwendinger, 1968; Francke and

Clark, 1974; Huddleston and Meyers, 1978; Brown et al., 1983; Flowers et al., 1984; Bleckmann et al., 1989). Whitfill and Boyd (1987) reported that soils may be treated with up to 5% oil by weight with no adverse environmental impact. Several studies have shown that controlled oil applications actually improve soil physical conditions and fertility status (Plice, 1948; Mackin, 1950; Ellis and Adams, 1961; Baker, 1970; Giddens, 1976).

Watts et al. (1982) measured a 2 year half life for a 14% loading of oil to soil. Streebin et al. (1985) also found a half life of about 2 years at a similar loading rate. At a loading rate of 2% in the field, 94% of hydrocarbons were removed after 3.5 years (Oudot et al., 1989). Lynch and Genes (1987) determined a half life of 77 days on a field plot containing 5% polyaromatic hydrocarbons.

2.4.4 Criteria

The API Environmental Guidance Document recommends a 1% oil and grease threshold for land disposal of E&P wastes based on attenuation and degradation processes that will occur under landspreading conditions. This value is predicated on the concept of minimum management, whereby an operator may load a soil (add hydrocarbon) at an appropriate mix ratio (E&P waste:soil) not to exceed 1% oil and grease. Available information demonstrates that 1% hydrocarbon by weight was a reasonable threshold initiating temporary plant yield reductions.

2.5 Conclusions

This information supports the guidance values that have been developed for the land disposal of Exploration and Production wastes. For a one-time application the guidance values are EC < 4 mmho/cm, SAR < 12, ESP < 15%, and O&G <1%. These guidance values have been developed to be generally applicable for any waste containing salts or petroleum hydrocarbons including E&P wastes. They are designed to protect the environment under conditions most likely to be found at E&P locations. While being generally applicable, it is up to the operator to determine whether they apply to his particular site.

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EVALUATION OF LEACHING AND GYPSUM FOR ENHANCING RECLAMATION AND REVEGETATION OF OIL WELL RESERVE PITS IN A SEMIARID AREA

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Summary

Leaching a saline-sodic soil (initial EC 73 to 143 dS m^{-1}; initial SAR 63 to 90) with 1 m of good quality water (EC <2 dS m^{-1}) reduced EC by an average of 59% and SAR by an average of 43% in the surface 45 cm. Subsequent surface applications of 8 to 9 Mg ha^{-1} of gypsum and sprinkler irrigation (280 mm) did not further reduce EC or SAR values, possibly because of slow and ineffective gypsum dissolution. Survival and canopy height of fourwing saltbush (Atriplex canescens) and oldman saltbush (Atriplex nummularia) transplants were not affected by gypsum treatment 5 months after planting. Survival of transplanted fourwing saltbush seedlings was about 65% after 38 months, but survival was not affected by gypsum treatment. All oldman saltbush seedlings died as a result of winterkill.

Introduction

On-site disposal of petroleum and natural gas drilling fluids in arid and semiarid regions usually results in long-term soil disturbance and contamination. High concentrations of soluble salts in these wastes, primarily NaCl, often seriously inhibit germination and establishment of most native plant species (1).

Earthen basins (reserve pits) about 30 to 60 m^2 and <1 m deep are constructed adjacent to each drilling site and used for handling, storage and disposal of drilling fluids. When drilling is completed, the drilling fluid and cuttings are usually allowed to dry in the reserve pit, and then mixed with soil from the pit borders.

Typical drilling fluids consist of a 5% slurry of bentonite in water or brine with NaOH added as a dispersant, an organic material such as lignite or lignosulfonate to stabilize the slurry, and a density-increasing material, usually barite ($BaSO_4$), to float out rock particles (2). High salt concentrations characteristic of drilling fluids are caused by chemical additives, by contact with certain subsurface geologic formations during drilling, or by the use of brine as the carrier. Ten individual drilling fluid components significantly reduced yields of corn (Zea mays var. saccharata) and beans (Phaselous vulgaris) (3). High total soluble salt concentrations (EC) or high exchangeable sodium percentages (ESP) caused by additions of KCl, NaOH, and $Na_2Cr_2O_7$ in 1:1 and 1:4 mixtures of drilling fluid and soil were the primary causes of reduced plant growth (4).

High osmotic potentials produced by soluble salts retard water imbibition by seeds, resulting in decreased germination and slower seedling emergence rates (5). Transplanting seedlings bypasses the critical phases of seed germination and seedling establishment. Many shrub species are well adapted to droughty and saline conditions because of structural and/or physiological adaptations of roots and foliage (6,7). However, even the use of halophytic shrub seedlings may not result in successful revegetation of severely contaminated soils. Survival of fourwing saltbush (Atriplex canescens) transplants was only 26 and 30% 2 years after planting on soils with EC values of 71 to 114 dS m^{-1} in western Texas (1). The use of more intensive soil reclamation practices, such as leaching and/or the use of soil amendments, may be necessary in such cases.

Leaching, either by rainfall or irrigation, is the primary method used for removal of soluble and exchangeable salts from contaminated soils. The effectiveness of intermittent ponding or sprinkler irrigation has generally been greater than that of continuous ponding (8,9). However, Na saturation of the soil cation exchange complex results in clay dispersion, decreased permeability, and a reduction in soil leachability. Chemical amendments which supply soluble Ca facilitate removal of exchangeable Na by leaching. Gypsum ($CaSO_4$), elemental sulfur (S), $CaCl_2$, and HCl have been used for reclamation of calcareous saline-sodic soils in southern New Mexico (10). Gypsum is most commonly used due to cost, handling and availability considerations.

Surface applications of gypsum were reported to be more effective than incorporation for increasing exchangeable Ca-ion and hydraulic conductivity (11). Soluble carbonate precipitated when gypsum was incorporated into soil, while leaching after surface applications of gypsum removed much of the soluble carbonates prior to reaction. As a result, surface application rates of gypsum could be reduced by as much as 50%.

Plant responses to gypsum treatments have been variable (12,13,14,15). Infiltration rates and plant yields have increased after gypsum applications on some salt-affected soils (12,15). However, gypsum applications at rates as high as 21.6 Mg ha^{-1} did not improve growth of native plants on salt-affected soils in the Northern Great Plains (13). Applications of gypsum at 2 to 14 Mg ha^{-1} to a fine-textured saline-sodic soil in India did not affect growth or yield of cotton (Gossypium hirsutum) or sorghum (Sorghum bicolor) (14).

The objectives of this study were to investigate the effects of leaching and leaching plus surface applications of gypsum on soil chemical properties and on survival and growth of two facultative halophytic shrub species on saline-sodic reserve pit soils in the southwestern United States.

Materials and methods

The study was conducted in the northern Edwards Plateau of Texas 10 km northeast of Big Lake in Reagan County (31°15'N 101°40'W). The climate is semiarid with an average annual precipitation of 414 mm and a mean annual pan evaporation of 1800 mm (16). The average daily maximum temperature in July is 36 C and the average frost-free period is 229 days. The study area was on a level, upland site on a Reagan clay loam (fine, mixed, thermic Ustollic Calciorthid). The Reagan series consists of deep upland soils formed in calcareous, loamy sediment of ancient outwash and aeolian origin. Slopes at the study site were ≤1%. Physical and chemical properties of the native soil and drilling fluids characteristic of the study area are presented in Table 1.

Native vegetation at the study site is characterized by buffalograss (Buchloe dactyloides), red threeawn (Aristida longiseta), and tobosagrass (Hilaria mutica). Major forbs include broom snakeweed (Gutierrezia sarothrae), desertholly (Perezia nana), and leatherweed croton (Croton pottsii). The area also supports a moderate stand of honey mesquite (Prosopis glandulosa var. glandulosa).

Earthen berms were constructed around the perimeters of three reserve pits exhibiting extremely high levels of salt contamination and each pit was

flooded with 1.0 m of good quality (EC <2.0 dS m^{-1}) water in March 1984. Soil cores were collected from six permanently marked sampling locations on each pit at 0 to 15-, 15 to 30- and 30 to 45-cm depths prior to flooding and shortly after infiltration of ponded water. Samples were air dried, ground to pass a 2-mm sieve, and analyzed for exchangeable Na and cation exchange capacity (CEC) (17). Each pit was divided into two plots, one of which received a gypsum treatment on 12 June 1984. Gypsum application rates were determined using a modification of the formula developed by Doering and Willis (18): $GR = (CEC)(ESP_{initial} - ESP_{final})/100$, where GR (gypsum requirement) and CEC are in cmol kg^{-1}.

Fourwing saltbush seedlings were transplanted on 2-m spacings on half of each plot and oldman saltbush (Atriplex nummularia) seedlings were transplanted on 2-m centers on the other half of each plot on 12 June 1984, providing about 20 seedlings per subplot. Fourwing saltbush is a native, evergreen shrub commonly used for revegetation of disturbed soils in the southwestern United States (1,19). Oldman saltbush is an introduced, evergreen shrub commonly used for revegetation of salt-affected land in western Australia (20,21). Both species are facultative halophytes.

The fourwing saltbush seed from which transplants were grown had been collected from a native population growing on a saline-sodic soil 10 km west of Big Lake. Oldman saltbush seeds were purchased from a commercial firm in western Australia. Seedlings of fourwing and oldman saltbush were grown in a greenhouse in a 2:1:1 (v:v:v) peat moss/vermiculite/soil mixture and were 4 months old at time of planting. All transplants were pruned to 10-cm heights prior to planting.

Gypsum was applied at 8 to 9 Mg ha^{-1} to one plot on each reserve pit immediately after planting. About 280 mm of additional water was applied to all plots by sprinkler irrigation during the next 2 months for additional leaching.

Five soil cores were collected from 0 to 15-, 15 to 30- and 30 to 45-cm depths along one diagonal of each plot 15 and 38 months after gypsum applications. Samples were prepared as described previously and used for laboratory determination of electrical conductivity of the saturated paste extract (EC) and sodium adsorption ratio (SAR) (17). Plant survival and canopy height of the shrubs were determined 5 and 38 months after planting by counting the number of live plants in each subplot and by measuring the height of each live plant.

Experimental design was a randomized complete block, with three replications. Soil data were treated as a split plot, with gypsum as the main plot effect and time as the subplot effect. Vegetation data were

treated as a split plot with gypsum as the main plot and species as the subplot. Data were subjected to analyses of variance, and means were separated by Duncan's multiple range test where appropriate (22).

Results and discussion

Annual precipitation at the study site was ≥ the 21-year average in 1984 through 1987 (Table 2). Flooding with 1 m of water significantly decreased EC and SAR in the surface 45 cm of soil (Table 3). Soil EC values ranged from 73 to 143 dS m^{-1} before flooding and from 34 to 48 dS m^{-1} after the water infiltrated and the soils had dried, reflecting a 53 to 66% reduction. Soil SAR values decreased by 35 to 58%. Initial SAR values were 63 to 90 and were 38 to 43 after flooding. Although reductions in salt levels were substantial, leaching did not reduce EC and SAR levels sufficiently for growth of non-halophytic plants.

Electrical conductivities and SAR values after 15 months tended to be greater on plots receiving gypsum than on untreated plots, but differences were not significant (Table 4). The large variability in EC and SAR within pits after 15 months probably masked treatment effects. The conventional practice of mixing soil with drilling wastes results in considerable spatial variation and exacerbates the difficulty in assessing the level of site contamination.

Electrical conductivities and SAR values of gypsum-treated and untreated plots were similar after 38 months (Table 4). Gypsum reduced both EC and SAR slightly over time, but differences were not significant. Failure of gypsum to reduce salinity levels in these soils may have been due to slow and ineffective gypsum dissolution caused by high SO_4-ion concentrations in the soil-drilling fluid mixtures. Weber et al. (23) reported that high SO_4-ion levels in water used for leaching reduced the efficacy of gypsum for reclamation of sodic mine spoils. Reduced effectiveness of gypsum in reclamation trials on saline-sodic soils high in SO_4-ion has also been observed (9,24). High concentrations of SO_4-ion in leaching water or soil retard dissolution of gypsum due to the common ion effect. Soluble SO_4-ion concentrations in drilling fluids used in the region commonly range from 10 to 12 mmol L^{-1} (1). The concentration of SO_4-ion in the water we used for leaching was not determined.

Gypsum treatments did not affect survival or canopy heights of transplanted fourwing and oldman saltbush 5 months after planting (Table 5). All oldman saltbush plants died during the winter of 1984-85, apparently because of freeze damage. Extended periods (2 to 4 days) of sub-freezing (<0 C) temperatures occurred during that time. Use of oldman saltbush appears to be limited to regions with more moderate winter temperatures.

Survival and canopy heights of fourwing saltbush transplants were also not affected by gypsum application after 38 months (Table 5). Seedling survival was satisfactory at 63 and 65% on plots with and without gypsum, respectively.

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Table 1. Physical and chemical characteristics of soil and drilling fluids from the study area

Parameter	Soil[1]	Drilling fluid[2]
Texture		
Sand (%)	28	28
Silt (%)	34	42
Clay (%)	38	30
Class	clay loam	clay loam
pH	7.5	7.5
CEC (cmol kg^{-1})	32	25
EC (dS m^{-1})	1	174
SAR	0.2	199
ESP	0.3	65

[1]Average values for the surface 45 cm of soil, including A1, A2 and Bw1 horizons.
[2]Average values for four drilling fluids.

Table 2. Monthly precipitation (mm) for the study area, 1984 through 1987

Month	1984	1985	1986	1987	21-year average
January	25	0	6	4	13
February	6	20	34	50	18
March	8	24	4	37	19
April	0	14	63	25	33
May	19	67	114	166	52
June	44	45	75	81	49
July	50	50	19	2	42
August	1	11	76	71	39
September	93	80	61	9	56
October	75	63	169	-[1]	52
November	41	5	14	-	24
December	43	0	84	-	17
Total	405	379	719	445	414

[1]Rainfall data were not collected at this time.

Table 3. Soil electrical conductivities and sodium adsorption ratios at three depths on oil well reserve pits before and after flooding

	EC (dS m^{-1})		SAR	
Depth (cm)	Before flooding	After flooding	Before flooding	After flooding
0 to 15	143 a[1]	48 b	90 a	38 b
15 to 30	86 a	37 b	67 a	43 b
30 to 45	73 a	34 b	63 a	41 b

[1]Means within EC or SAR and depth followed by the same lower case letter are not significantly different ($P \leq 0.05$) according to Duncan's multiple range test.

Table 4. Soil electrical conductivities and sodium adsorption ratios at three depths on oil well reserve pits 15 and 38 months after gypsum application

	EC (dS m^{-1})		SAR	
Depth (cm)	Gypsum	No gypsum	Gypsum	No gypsum
	----------(15 months)----------			
0 to 15	81[1]	38	68	55
15 to 30	53	22	72	49
30 to 45	60	16	77	40
	----------(38 months)----------			
0 to 15	46	47	42	60
15 to 30	32	39	52	62
30 to 45	31	33	55	59

[1]Means within EC or SAR and within a collection period and depth were not significantly different ($P \leq 0.05$).

Table 5. Survival and canopy heights of transplanted fourwing saltbush and oldman saltbush seedlings on oilwell reserve pits 5 and 38 months after gypsum application

Species	Survival (%)		Height (cm)	
	Gypsum	No gypsum	Gypsum	No gypsum
	(5 months)			
fourwing saltbush	64[1]	70	22	22
oldman saltbush	88	75	21	22
	(38 months)			
fourwing saltbush	63	65	110	120
oldman saltbush	0	0	-	-

[1]Means for survival or canopy height within a collection period were not significantly different ($P \leq 0.05$).

EVALUATION OF OILY WASTE INJECTION BELOW THE PERMAFROST IN PRUDHOE BAY FIELD, NORTH SLOPE, ALASKA

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Abstract

This paper presents the results of an extensive study and field test carried out at the site of Prudhoe Bay's four oily waste injection wells. The field work was part of an overall environmental assessment intended to: (a) confirm earlier results indicating that no fluid communication was occurring with the permafrost; (b) determine optimum conditions for the disposal of waste in the presence of hydraulically induced fractures; (c) substantiate that an increased injection pressure could be safely implemented. A three-day injection test, including a step-rate stage, was carried out. Data collected included surface and downhole pressures, in-situ stress measurements, and monitoring of ground surface deflections and wellbore hydraulic impedance.

Radially symmetric surface tilt patterns showed that the test well was connected to a horizontal fracture of 60-foot radius. Wellbore impedance measurements indicated that a horizontal fracture with a 9-18 foot radius communicated with the well. Integration of rock mechanics, historical information, and the collected data provided a clear picture of what was occurring underground. The different evaluation techniques showed consistent results as reflected in estimated fracture size, placement, and damage zone properties.

Introduction and Overview

In 1973, five wells drilled to a 2200-foot depth in Prudhoe Bay Field formed a five spot pattern with a lateral spacing of 23 feet. They were used for an extensive thaw subsidence test, then shut-in. They were later converted to injection for waste fluid disposal under a Class II UIC permit. The Center well was never perforated and the Northeast well has been abandoned. Fluids can be directed to any one of the remaining three. Each well has 20-50 feet of casing perforated at 2000 feet, approximately 150 feet below the base of the permafrost. Injection is intermittent, depending upon when trucked fluids arrive at the site. The plant typically operates at a 900± psi discharge pressure which means the rate usually varies between 1-2 bpm, depending upon fluid characteristics. Approximately 3 million barrels have been injected. Disposal rates average 600 bpd with peak rates of 6000 bpd.

A simple description of the injection stream is difficult because of its many sources. Predominantly it consists of waste waters, but also includes contaminated crude oil, vessel sludge, acids, unused frac sand, gels, drilling muds, stimulation fluids and formation fines, unset cement, tank bottoms, and solutions of methanol and glycols. The range in temperatures, viscosities, and densities is large. The solids content is sometimes very high.

Continued efficient fluid disposal will require an injection pressure of 1200 psi. When a Class-I UIC permit was sought in 1986, a 1400 psi limit was requested. The elevated pressure was provisionally allowed; however, it has gone through an extended review in light of new regulations. Central issues of concern have been the need to demonstrate that a 1400 psi pressure is necessary and safe, that the confining zone is not being fractured, and that no fluids are penetrating the confining zone or damaging the permafrost. It was decided that definitive reservoir modeling, actual field tests, and/or other supportive, correlative data would be required during the regulatory review process.

Geology and Sedimentology

Figure 1 shows a typical subsurface log of the injection interval. The wells are perforated in a heterogeneous interval of thinly bedded shales, siltstones and sandstones, 30 feet below a laterally continuous thick bedded sandstone with excellent porosity and permeability, and 150 feet below permafrost. Above the sandstone unit at the permafrost base lies a shaly interval which is believed to be an effective barrier to upward fluid flow. These sands rise toward the southwest and eventually intersect the permafrost.

Geologic and sedimentation studies of the lithologic column above the injection zone are detailed in a 1970 Alaska Test Lab Report[1]. This work outlined mechanistically how the permafrost was most probably formed, and suggested that although the stress fields appeared normal, they may differ from those that exist in more conventional depositional environments.

Injection Zone Performance From Conventional Data Analysis And Prior Measurements.

- A general plugging of the zone was suspected and subsequently confirmed by an interference test in which virtually no communication existed between the wells. Further, it was calculated that total plugging of the porosity could be expected to a radius of 70+ feet using a conservative volume for injected solids.

- Falloff tests showed that the injection zone was not overpressured. These tests indicated severe wellbore damage existed, but no major fracturing was evident from the data. Further interpretation was inconclusive and it was felt that additional conventional pressure testing was useless.

- Surveys demonstrated that the perforated interval was in communication with the sandstone interval just below the permafrost; however, no uphole channeling behind pipe was occurring as evidenced by three pump-in temperature surveys.

- Sonic/Radioactive logging and casing strain measurements confirmed that the sandstone/shale rock units were reacting very differently to the dynamic forces resulting from radial thawing of the permafrost around the well casings.[2] The combined effects further compact the shales, bond the casings, and successfully prevent vertical fluid movement of injected fluids.

- Increasing, and sometimes unusual, injection pressure spikes could be explained by progressive permeability reduction in the local region surrounding the wellbores, coupled with the existence of a fracture system that was opened and closed.

- Depositional studies indicated that theoretically, the stress regime favored creation of horizontal fractures over vertical fractures. In total, it was concluded that there was no evidence of permafrost fracturing or confining zone penetration.

Test Plan and Objectives

To substantiate the safe use of a 1400 psi injection pressure, an extensive field test was devised. The goals were to fully understand the response of the injection zone when waste was injected at normal operating conditions, to obtain sufficient technical backup to support the permit request for 1400 psi, and to determine what realistic limit was possible on pressure or rate without penetrating the lower confining zone.

To achieve these objectives, it was felt necessary to obtain the following data:

- Record the deformation of the earth's surface during an injection operation since this is a function of the subsurface anomaly resulting from the injection. Surface tilts describe the plane and azimuth of any created fracture, or the absence of it. The tilt vectors provide very different signatures for vertical and horizontal fractures[3]. Monitoring the vectors' progressions during an injection operation can also establish the responsive nature of the near wellbore region.

- Measure the borehole impedance prior to, during, and immediately following fluid injection[4]. Pulsing the injection stream and measuring the free pressure oscillations is indicative of the existence and, to a lesser degree, the geometry (size and orientation) of any hydraulic fracture connected to the wellbore.

- Determine the mechanical rock properties via sonic logging, using state-of-the-art tools. This would allow calculation of the minimum horizontal stress profile.

The Field Injection Test

Implementation consisted of pumping fluids at various rates into the southeast well while monitoring surface and downhole pressures. The surface pressure was sampled 150 times per second for the free oscillation studies. Ground surface tilt rates were monitored before, during, and after the stimulation, with a surface array of 17 high gain tiltmeters, to determine source characteristics of any fractures that formed as a result of the injection. Free oscillation pulse and decay experiments were conducted throughout the injection periods to monitor wellbore impedance.

The surface array of biaxial tiltmeters is shown in Fig. 2. It consisted of two concentric circles with radii of 38 and 50 percent of the injection depth to optimize the signal-to-noise ratio. Maximum surface tilts for a horizontally oriented fracture occur at a radius of 800 feet. As shown in Fig. 3, the maximum expected signal amplitude was 390 nanoradians. For a vertically oriented fracture, the maximum tilt magnitude is approximately one-fourth the magnitude of a horizontal fracture and occurs at a radius of 1000 feet. Installation holes for the tiltmeters consisted of 8-inch pipe cemented 25 feet into the permafrost.

Background data from the 34 tiltmeter channels was collected for six weeks. Sampling intervals averaged eight minutes. The interval was decreased to once per minute during the injectivity/fracture testing period. Data was transmitted from each instrument via cable to a centralized dual computer system. The three-day test consisted of the following pumping sequence:

Stage 1) 1000 bbls of 27 API crude oil pumped at 2 bpm; 38 cp viscosity, BHP-1400 psi
Stage 2) 1000 bbls of 27 API crude oil pumped at 4.8 bpm; 38 cp viscosity, BHP-1500 psi
Stage 3) 800 bbls crosslinked gel pumped at 8-10 bpm; 68 cp FANN viscosity, BHP-1700 psi

Tilt Meter and Wellbore Impedance Results

Surface deformations associated with each of the injection periods are detailed in the consultant's report[5]. Figure 4 shows examples of raw tilt data for station five during the second day of testing. Data quality was excellent as all channels recorded the solid earth tides and induced deformations. The tiltmeter noise levels were extremely low, averaging one nanoradian. Figures 5-7 provide a summary of the final tilt vectors at the end of each pumping period.

1. The injection periods lasted different lengths of time, yet the total accumulated surface tilt magnitude for each period was virtually identical. A single vertical planar dislocation could not be made to fit the recorded signatures. However, the radially symmetric tilt patterns could be modeled by subhorizontal, rectangular, mode-1 dislocations.

   An inversion analysis indicated that the tip-to-tip length of the modeled horizontal fractures did not exceed 140 feet and the fracture opening was approximately 0.3 inches. The maximum fracture radius was approximately 70 feet. The modeled fracture volume averaged 327 cubic feet, and fracture fluid efficiency was extremely low, averaging 0.058. This means that 94 percent of the injected fluid leaked into the formation. If any portion of the leak-off dilated the formation and contributed to the observed deformations, then the modeled fracture volume would be proportionately decreased.

2. The above analysis assumes that the dislocation source is a planar feature. However, spherical source distributions also produce radially symmetric surface tilt patterns. If a discrete fracture did not form and the injected fluid only diffused outwardly, dilating a highly permeable zone, then the integrated effect when modeled as a dislocation source would appear as a horizontal planar feature with the same characteristics outlined above in item 1. Inversion of the surface tilts, assuming that a spherically dilatant source geometry exists, is highly non-unique since the source parameters appear as multiplicative terms in the theoretical expression for surface tilts. A typical inversion solution for spherical source parameters for the third stage injection yields a fluid infiltration radius of 62 feet, $dp/G = 0.00125$. The dimensionless ratio dp/G typically ranges from 0.0001 to 0.001. It relates the net pressure above overburden pressure in the fluid infiltrated region, dp, to the formation shear modulus, G. Based upon this range in dp/G, the upper and lower limits for fluid infiltration radius probably range from 50 to 100 feet. The possibility that a spherical source existed was repeatedly examined [5, 6], yielding an average 72 foot dilated radius.

3. The tilt data alone cannot distinguish between a dilatant source geometry and a horizontal, planar source; however, the above indicators allow us to conclude that the well is connected to either a horizontal fracture or a spherically dilated zone. In this instance, the inability to distinguish between the competing geometries is due to the radial symmetry of the observed surface tilt field. If a fracture had been created that was either steeply dipping or vertical, then the possibility of a spherical source geometry could be eliminated and a plot of the resulting azimuth and dip constructed.

4. Wellbore impedance measurements clearly indicate the existence of a fracture[7]. A horizontal fracture, with radii calculated for the three stages of pumping, varied between 9-18 feet as illustrated in Fig. 8. The data could also be made to fit (to a lesser degree) a contained vertical fracture 5 feet high and 80 feet long, an unreasonable dimension. Therefore, it is concluded that the impedance calculations support the existence of a horizontal fracture.

Pressure Transient Analysis and Observations

Quantitative interpretation of the pressure transient data is difficult if not impossible because of the complex mobility profile. However, qualitative inspection of the step-rate and falloff data support either a no-fracturing situation or a short radius horizontal fracture. Specifically:

1. Step-rate data from a vertical fracture shows a distinct decrease in slope on the Cartesian plot of pressure-versus-rate when injecting above fracturing pressure. The change in slope is a reflection of the improvement in the well's injectivity resulting from the shift from radial to linear flow regimes. Data in Fig. 9 does not show the decrease in slope; rather, it increases. In the case of a horizontal fracture of short radius, the increase in injectivity is insignificant in a relatively thick formation. Gringarten and Ramey (1974) have shown that in a formation such as this, a short horizontal fracture does not significantly enhance a well's performance. The increase in slope seen here can only be explained as a result of short injection time.

2. Inspection of the falloff data after each period did not show indications of fracture closure. Multi-rate analysis following the second injection period, assuming radial flow existed, gives a mobility of 46 md/cp. This is indicative of fluid entering 1-2 darcy rock.

Measurement of In Situ Stresses

The minimum closure stress was measured using the breakdown test technique. Measured fracture gradients ranged from 0.82 to 0.85 psi/ft. The overburden gradient, calculated from the porosity-density log profiles, was estimated between 0.80 and 0.90 psi/ft. Hence, it almost equals the measured gradients. These numbers indicate horizontal fractures should occur at the injection horizons. This conclusion is supported by the fracture reopening pressure which was measured at 1590 psi during the step-rate test while pumping gelled fluid.

Comparative Considerations

Basic fracture theory[8], coupled with the high permafrost plasticity, suggests that multiple or successive horizontal fractures are possible when plugging of earlier fractures occurs. This phenomenon has been observed and mapped at a similar facility[9-11]. At Oak Ridge in Melton Valley, radioactive grout has been successfully injected into shallow shale layers since 1959. Seven fractures were mapped and all appeared to be nearly horizontal. This phenomenon may also be occurring here.

Summary and Concluding Remarks

1. The surface tilt data was generated by a horizontal fracture of approximately 60 feet radius at all three injection rates. No vertical fracturing was discernible. This result agrees with

fracture theory and was also verified qualitatively by impedance analysis. Step-rate testing and pressure falloff data support this finding.

2. The horizontal stress above 2000 feet appears to equal or exceed the vertical stress. This North Slope data tends to agree with observations in other localities around the world, and hence leads us to believe that any subsequently created fractures will also be basically horizontal in nature. Further documentation on this can be provided.

3. Test data confirmed that the injection process occurred through a horizontal conduit that penetrates a severely damaged region. While the damaged area may contain some secondary conjugate fractures, no principal vertical fracture exists.

4. Localized radial thawing around the wellbores has had no effect on vertical fluid movement. Lithologic heterogeneities and permafrost rock mechanics have combined to prevent vertical migration of the dirty wastes. This is to be expected, since the injection zone is not overly pressured and is overlain by an essentially impermeable barrier.

5. In total, the study confirmed that the reservoir provides a good waste disposal site. Injection at a sustained rate of 4 bpm will pose no problem. With the current well completions, the use of surface pressures up to 1400 psi is safe. Temporary rate increases to 6-8 bpm can occur without risk of forcing fluids into confining zones or damaging the permafrost at the site.

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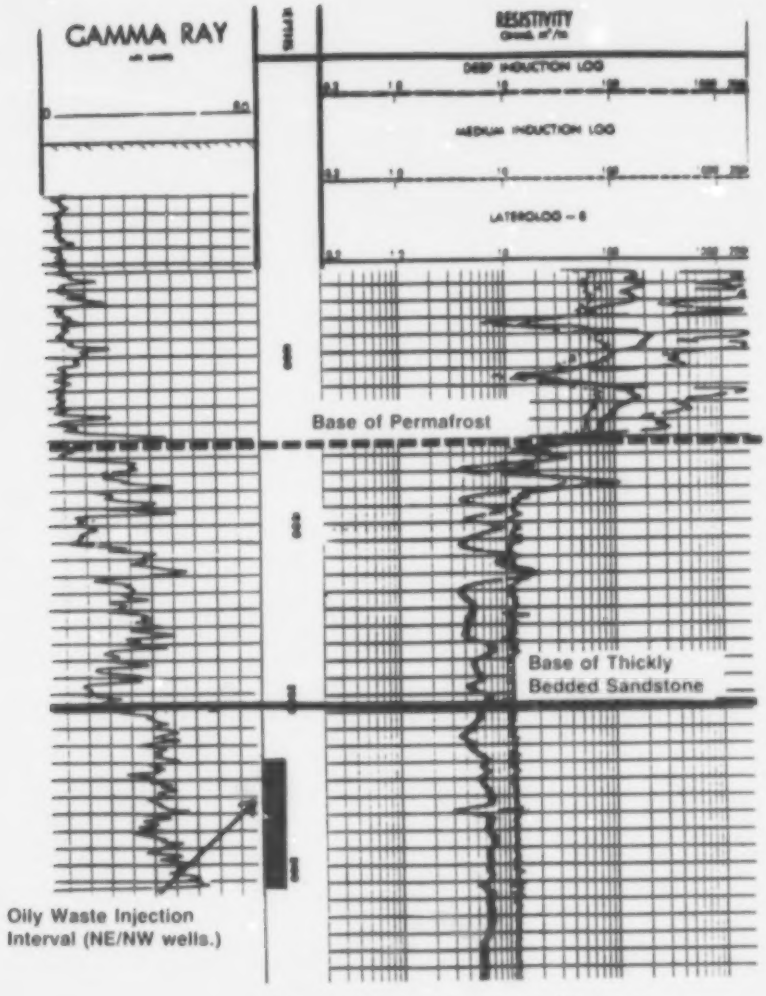

Fig. 1—Typical log for OWI wells.

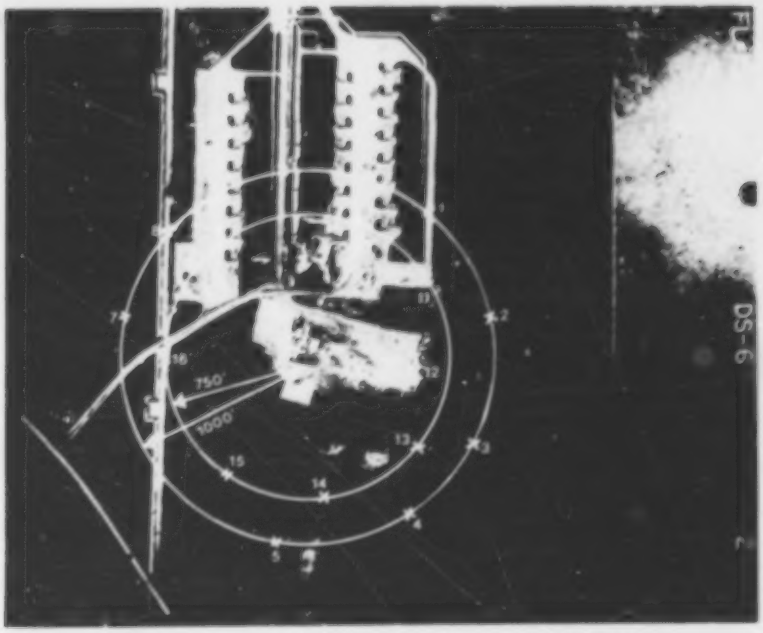

Fig. 2—Tilt meter location map around pad 3.

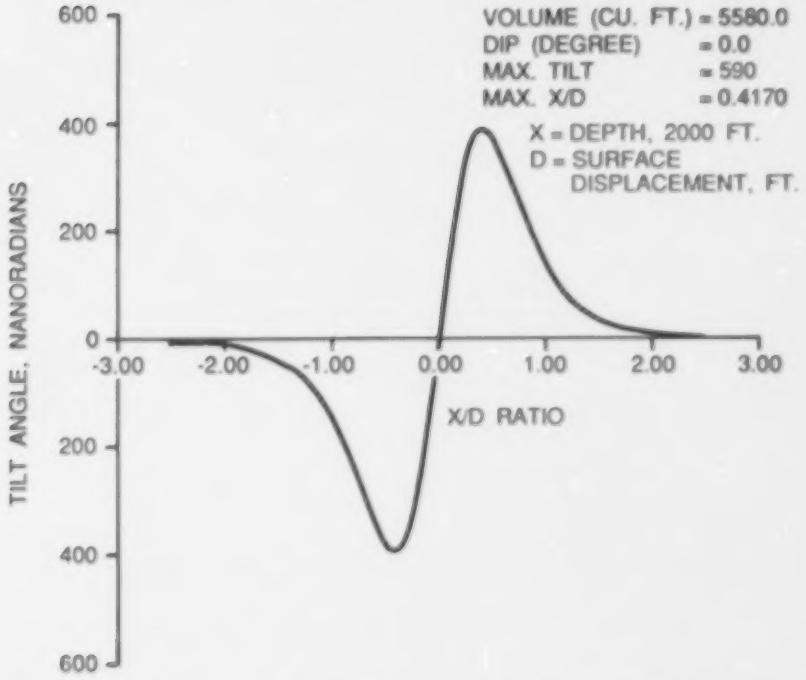

Fig. 3—Theoretical tilts for a 1000 bbl horizontal dislocation at a depth of 2000 feet.

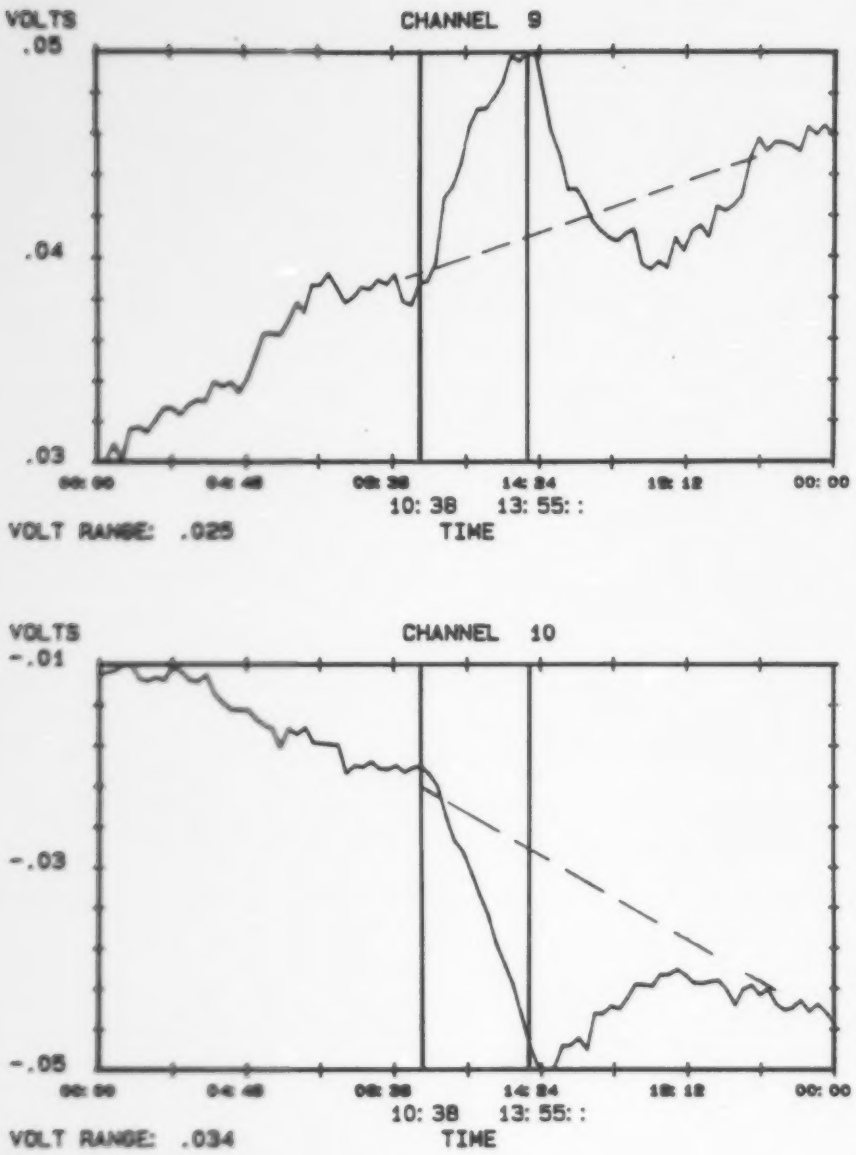

Fig. 4—Tilt record during the second day injection test showing effect of pumping.

Fig. 5—Tilt map at end of first day pumping.

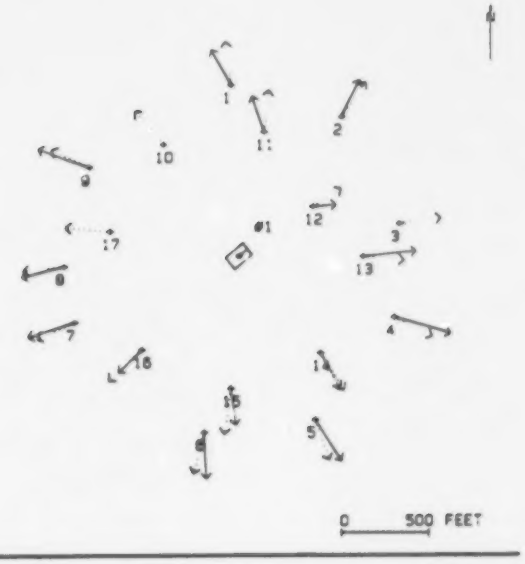

Fig. 6—Tilt map at end of second day pumping.

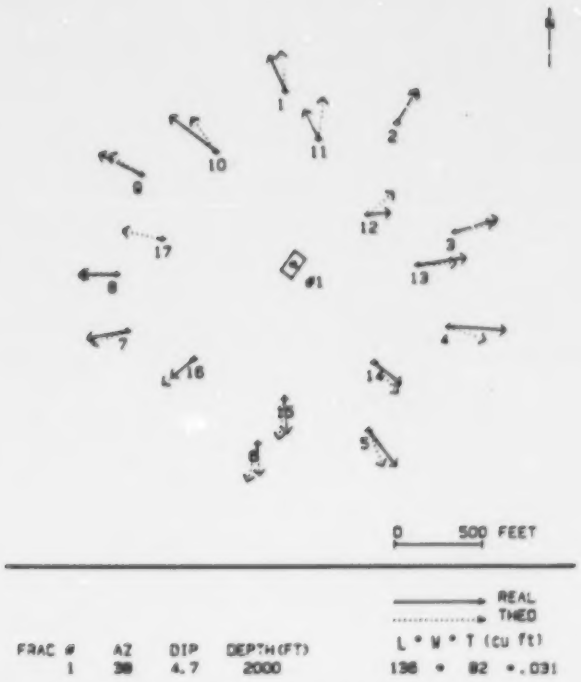

Fig. 7—Tilt map at end of third day pumping.

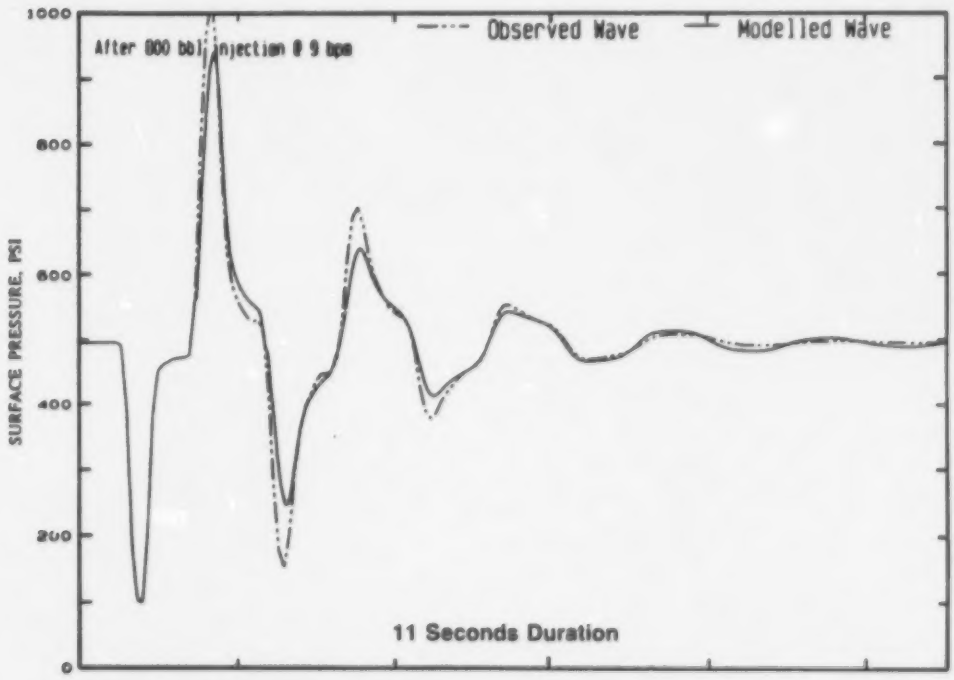

Fig. 8—Typical well impendance response during pressure pulsing.

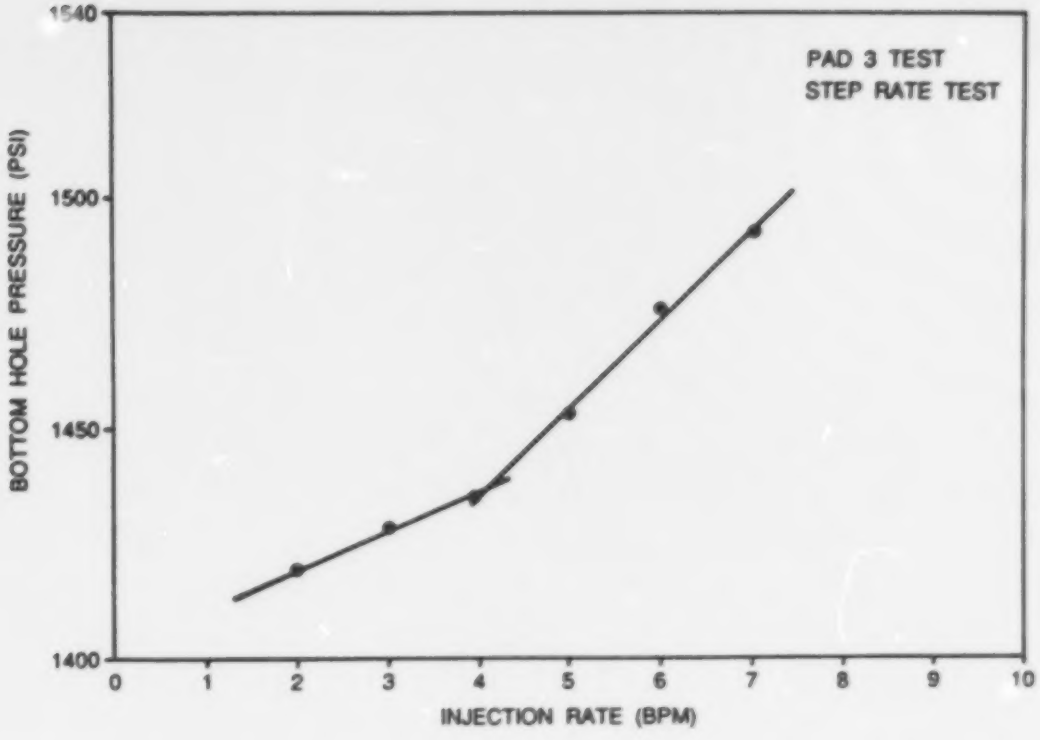

Fig. 9—Pressure-rate record during step rate test at pad 3 N.E. well.

EVALUATION OF SELECTIVE-PLACEMENT BURIAL FOR DISPOSAL OF DRILLING FLUIDS IN WEST TEXAS

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Introduction

Onsite, surface disposal of drilling fluids used in petroleum and natural gas exploration is a common practice in arid and semiarid regions of the southwestern United States, even though soils may be severely and permanently contaminated. Selective-placement burial, a technique developed for coal mine reclamation, presents an alternative to surface disposal in which drilling fluids are worked, stored, dried, and eventually buried at a predetermined depth below the soil surface. In this process, limited contact of soil and the contaminated wastes reduces the waste volume and preserves the quality of topsoil and subsoil essential for site reclamation.

This paper presents results of the 4-year evaluation of an experiment

initiated in 1986 to determine the effects of selective-placement burial of drilling fluids on soil chemical properties and on growth and chemical composition of two species used for revegetation. Data collected as of 20 months after treatment installation indicated that soluble salts migrated upward 15 to 30 cm into overlying soil and that capillary barriers of coarse limestone were only partially effective for reducing salt movement (1). No evidence was found to suggest that upward migration of heavy metals (Ba, Cr, Cu, Ni, Zn) contained in the drilling fluids and detected in concentrations near, or above, those in native soils had occurred. Survival and growth of fourwing saltbush (Atriplex canescens (Pursh) Nutt.) and buffalograss (Buchloe dactyloides (Nutt.) Engelm.) 17 months after planting were not affected by depth of drilling fluid burial, although significant increases in Na and K concentrations in both species at one location indicated plant uptake of drilling fluid constituents where burial depth was 30 cm (1). A more significant finding was evidence of elevated Zn concentrations in fourwing saltbush tissue on plots where drilling fluid was buried 30 or 90 cm.

Materials and Methods

The field study was established in 1985-86 in the northwestern Edwards Plateau of Texas. The study sites were 10 km north of Big Lake in Reagan County (Weatherby site) and 34 km southwest of Mertzon in Schleicher County (Mertz site). Reagan County is semiarid with an average annual rainfall of 430 mm and a mean annual lake evaporation of 1800 mm. The study area was on a level, upland site on a Reagan clay loam (fine, mixed, thermic, Ustollic Calciorthid). The average annual rainfall in Schleicher county is 460 mm and the mean annual lake evaporation is 1780 mm. The study site was on a flat valley floor above the overflow zone on an Angelo clay loam (fine, mixed, thermic, Torrertic Calciustoll).

Fifteen, 12- by 12-m simulated reserve pits separated by 15-m buffers were constructed at each location in August 1985 using a bulldozer. Treatments included burial of drilling fluid 30, 90, or 150 cm, burial 90 cm with a 30-cm capillary barrier of coarse limestone (Edwards Group) immediately above the drilling fluid, and an undisturbed control from which existing vegetation was cleared with the dozer blade. Topsoil and subsoil were removed and stockpiled separately during pit construction. Spent drilling fluids from two drilling locations near each study site were transported to the areas in dump trucks in September 1985. Equal volumes of about 25 m^3 of drilling fluid were placed as a uniform 30-cm layer into each pit, allowed to dry, and then covered by sequential replacement of subsoil and topsoil in January 1986. Experimental design was a randomized complete block arranged as a split plot with three replications. Replications were blocked by drilling fluid source.

The study sites were fenced to exclude livestock and lagomorphs, and field plantings were established in spring 1986. Each reserve pit plot

was divided into two, 6- by 12-m subplots. Fourwing saltbush (Atriplex canescens (Pursh) Nutt.), a native, evergreen, halophytic shrub, and "Texoka" buffalograss (Buchloe dactyloides (Nutt.) Engelm.), a native, perennial, warm-season shortgrass were used to evaluate the effects of plant material on contaminant migration. Forty seedlings of buffalograss were transplanted on 1-m centers on one subplot of each pit. Seedlings were grown in a greenhouse in an equal-volume peat moss\vermiculite\soil mixture in 4- by 5- by 18-cm polyethylene containers. Twenty-four, 1-year-old rooted stem-cuttings of fourwing saltbush were transplanted on 1.5-m centers on the other subplot. Stem-cuttings were taken from mature plants which were established in 1982 on a highly saline reserve pit (EC = 90, SAR = 46) near Big Lake, Texas. The seed from which these shrubs were produced was harvested from a native population near Texon (Reagan County), Texas. Stem-cuttings were rooted for about 2 weeks in a 1:1 (v:v) sand\vermiculite mixture using an intermittent misting system in a greenhouse, and transferred to 4- by 5- by 18-cm polyethylene tubpaks containing an equal-volume peat moss\vermiculite\soil mixture.

Results from soil analyses conducted on samples collected 1, 8 and 20 months after pit coverage were reported previously (1). Data presented in this paper concerns results from similar analyses conducted on samples collected 44 months after pit coverage. Sampling trenches bisecting each plot were excavated to the soil/drilling fluid (or soil/limestone) interface using a backhoe. Samples were collected from the pit wall in 30-cm increments, with zones at the soil/drilling fluid and soil/air interfaces subdivided into 15-cm increments. Composited soil samples from each subplot were air-dried and pulverized to pass a 2-mm sieve. Samples were analyzed using methods reported previously (1).

Survival and growth of fourwing saltbush and buffalograss transplants were determined 41 months after planting using methods reported previously (1). Representative aboveground tissue samples were collected from 10 plants in each subplot in August 1989, oven-dried at 60 C, and ground to pass a 0.15-mm sieve. Total concentrations of Ca, Mg, Na, K, Ba, Cr, Cu, Ni and Zn were determined by ICP atomic emission spectroscopy after HNO_3-$HClO_4$ digestion of composited subsamples.

Soil data were treated as a split-split plot with depth of burial the main-plot effect, plant species the subplot effect, and time (20 and 44 months) the sub-subplot effect. The data were subjected to analyses of variance and treatment means separated where appropriate using Fisher's least significant difference method. Plant data were subjected to split plot analyses of variance, where depth of burial was the main plot effect and plant species was the subplot effect. Means were separated by Duncan's new multiple range test where appropriate.

Results and Discussion

Physical and chemical characteristics of the native soil profiles and the drilling fluids used at each study site were reported previously (1). Salt contamination was the predominant concern as evidenced by drilling fluid EC values of 155 to 185 dS m^{-1} and ESP values of 42 to 89. Sodium and Cl^- were the dominant soluble ions, although K^+, Ca^{+2}, and Mg^{+2} concentrations were also much greater in drilling fluids than in native soils. Among-treatment comparisons of upward contaminant movement in the reconstructed soil profiles were facilitated by redefining the soil/drilling fluid (or soil/limestone) interface as the zero point. Treatment comparisons for EC and ESP data were made within each increment above this reference point.

Rainfall at the Weatherby site during 1988 and 1989 totalled 454 and 281 mm, respectively, compared to the long-term annual average of 415 mm. On the Mertz site, rainfall totalled 514 mm in 1988 and 353 mm in 1989, compared to the long-term annual average of 466 mm. Thus, in the year preceding this evaluation rainfall was considerably less than the long-term averages at both study sites.

Salt movement into soil overlying drilling fluid was similar in subplots planted to fourwing saltbush and buffalograss, so the data were pooled for presentation. The time x depth of burial interactions were significant for EC in the 0 to 15-, 15 to 30- and 30 to 60-cm increments above drilling fluid on the Mertz site (Table 1). In the 0 to 15-cm increment, EC values in the 30- and 150-cm burial treatments increased significantly over time, and a similar trend was observed in the 90-cm treatment. The 90-cm + barrier treatment significantly decreased the extent of upward salt migration compared to other burial treatments after 44 months. Similar treatment effects were observed in the 15 to 30-cm increment. Electrical conductivities in the 90- and 150-cm treatments increased over time and were greater than those in the 30-cm and 90-cm + barrier treatments after 44 months. Evidence of salt migration from drilling fluid into the 30 to 60-cm increment was observed only in the 150-cm depth of burial treatment. The greater mean soil moisture content presumably maintained year-round at this depth below surface in the 150-cm treatment, which corresponds to much more shallow depths in the other burial treatments, may have facilitated greater salt movement by diffusion.

Patterns of salt movement from drilling fluid into overlying soil were somewhat different on the Weatherby study site. Mean soil EC values in the 0 to 15-cm increment tended to increase in all treatments from 20 to 44 months, but differences were not significant (Table 2). Averaged over depth of burial, electrical conductivities in the 15 to 30-cm increment increased significantly over time from 3.9 to 18.2 dS m^{-1}. The greatest EC values occurred in the 90- and 150-cm burial treatments (37.3 and 17.4

dS m^{-1}, respectively). However, mean EC values of 10 dS m^{-1} in the surface 15 cm of the 30-cm treatment represent salinities which will likely impair establishment of many non-salt-tolerant plant species. The capillary barrier tended to decrease average EC values only slightly in the 0 to 15- and 15 to 30-cm increments. Failure of the limestone material used at this site to provide an effective barrier was evident after 20 months (1). The time x treatment interaction was significant for EC values in the 30 to 60-cm increment. Both the 90- and 150-cm burial depths exhibited significant increases in EC values from 20 to 44 months. In contrast, the capillary barrier appeared to limit salt movement into this zone over time and resulted in significantly lower EC values compared to the 90- and 150-cm treatments after 44 months. There was no evidence of salt movement above the 30 to 60-cm increment on either study site.

Time and the time x depth of burial interaction were significant for ESP values in the 0 to 15- and 15 to 30-cm increments, respectively, on the Mertz site (Table 3). Averaged over depth of burial, ESP values in the 0 to 15-cm increment increased significantly over time from 5.7 to 13.6 after 44 months. The capillary barrier tended to reduce Na^+ accumulation on the soil cation exchange complex in this increment, but treatment differences were not significant. Conversely, at 15 to 30-cm above drilling fluid ESP values in the 30- and 90-cm + barrier treatments were <1 and were significantly less than those in the 90- and 150-cm treatments (5.1 and 6.9, respectively). Significant increases in ESP values in the 90 and 150-cm treatments over time corresponded with greater EC values in these treatments (Table 1). Exchangeable sodium percentages in the 0 to 15- and 15 to 30-cm increments on the Weatherby site increased significantly over time (data not shown). Depth of burial did not significantly affect ESP values, although the smallest increases were observed in the 90-cm + barrier treatment in both increments. No significant treatment effects on ESP values were observed above 30 cm.

Depth of burial did not significantly affect upward salt migration. However, increases in EC and ESP values in the 15 to 30-cm increment of the shallow, 30-cm treatment tended to be less than those observed for greater depths of burial. Lower soil water contents in this increment of the 30-cm treatment caused by evaporation may have reduced Na^+ diffusion. Soil columns open to evaporation have been shown to support less upward Na^+ movement than columns without evaporation, thus lower soil-zone water contents under evaporation reduce diffusion more than any concomitant increase of convective salt flows. The effect in this study was greater for the clay soil (Mertz site) than the clay loam (Weatherby site). Similarities in the nature of salt migration from different depths of burial suggests that diffusion is the dominant process affecting upward salt movement (1). Additional salt migration since the 20-month evaluation, particularly into the 30 to 60-cm increment,

indicates that an "equilibrium" condition has not yet been achieved with respect to upward salt movement.

Initial analyses of samples of the drilling fluids from each study site identified 5 metals (Ba, Cr, Cu, Ni and Zn) which occurred in concentrations near, or greater than, those in the native soil profiles (1). However, evaluations of soil samples collected from the 0 to 15-cm zone above drilling fluid 1 and 20 months after pits were covered showed no evidence of upward movement of these metals over time. Similar comparisons were made with data collected after 44 months and there was again no evidence of metal movement within the reconstructed profiles at 0 to 15- or 15 to 30-cm above drilling fluids (data not shown). These data support the contention that little or no movement of these metals should be expected in the alkaline, calcareous soils characteristic of this region due to sorption and/or precipitation reactions which immobilize them in or near the waste/soil interface.

Survival of fourwing saltbush transplants after 41 months ranged from 92 to 100% (data not shown). Depth of drilling fluid burial did not significantly affect saltbush survival. Spread and overlap of stolons of buffalograss transplants prevented measurement of individual transplant survival, but there were no indications of additional plant mortality after 41 months. Canopy cover of fourwing saltbush transplants 41 months after planting was significantly greater on plots with buried drilling fluids (45 to 76%) compared to control plots (22 to 32%) at both study sites (Table 4). However, average canopy cover of fourwing saltbush on the 30-cm treatment on the Mertz site was significantly less than those on other treatments with buried drilling fluid. A similar trend was observed for buffalograss on both sites, although differences were not significant. Fourwing saltbush canopy cover increased by 6 to 20% from the 17-month evaluation, while buffalograss canopy cover had decreased on most plots by 3 to 11%. Enhanced plant growth on plots with buried drilling fluid and attributed to the tillage effect associated with pit construction was still evident after 41 months.

Regression equations for estimating total aboveground biomass of fourwing saltbush were: $\log W = -5.024 + 0.918 [\log (4\pi r^3/3)]$ for the Mertz site, and $\log W = -7.660 + 1.063 [\log (\pi r^2 h)]$ for the Weatherby site, where r is the average plant canopy radius in cm, h is plant height in cm, and oven-dry weight (W) is expressed in g. These equations accounted for 89 and 97% of the variability in aboveground biomass for fourwing saltbush on the Mertz and Weatherby study sites, respectively. Fourwing saltbush biomass production was significantly greater on treated plots (11450 to 21501 kg ha^{-1}) compared to control plots (1749 to 4184 kg ha^{-1}) after 41 months (Table 4). This corresponded with results observed at 17 months, although saltbush yields increased by 561 to 14261 kg ha^{-1} after 41 months. Yields of fourwing saltbush on the Mertz site on plots with

drilling fluids buried 30 cm were significantly less than those on the 150-cm treatment. Buffalograss yields in the fourth growing season were 56 to 906 kg ha^{-1} less than those after two growing seasons. Results observed for plant canopy cover and biomass data may represent early indications of burial depth effects on plant performance. Below-average rainfall in 1989 probably limited plant growth, particularly on the shallow, 30-cm treatment, where rooting depth was restricted. Additional effects stemming from the impacts of greater rooting zone salinity on plant growth on the 30-cm treatment are likely, but not distinguishable.

Sodium concentrations in buffalograss growing on the 30-cm treatment on the Weatherby site were significantly greater than those in buffalograss growing on control or 150-cm burial treatments, and tended to be greater than those on the 90-cm and 90-cm + barrier treatments (Table 5). Similar results were observed for fourwing saltbush leaves on the Weatherby site. In contrast, there was no evidence of elevated Na concentrations in either species on the Mertz site. These site differences are likely attributable to greater upward salt migration which occurred on the Weatherby site (Table 2). The elevated Na concentrations were similar in magnitude to those observed at 17 months after planting. Thus, although additional upward salt movement occurred by 41 months, accumulations in plant tissue remained relatively constant. Concentrations of K in fourwing saltbush leaves growing on control plots at both locations were significantly less than those in plants growing on plots with buried drilling fluids. In contrast, concentrations of Ca in fourwing saltbush leaves growing on control plots at both locations, and saltbush stems growing on the Weatherby site were significantly greater than those in plants growing on treated plots. A similar trend was observed for Mg concentrations in fourwing saltbush leaf tissue on the Weatherby site. These results were attributed to residual effects of pit construction on plant growth (tillage effect) and nutrient availability (soil profile mixing).

There was no evidence of accumulation of Ba, Cr, Cu, Ni or Zn from drilling fluids by fourwing saltbush or buffalograss plants growing on either study site after 41 months. These results corresponded with those observed at 17 months, and indicated that profile disturbance was the primary factor influencing treatment differences for these metals.

Conclusions

Burial of spent drilling fluids in arid and semiarid environments represents a viable alternative to the conventional method of surface disposal. Soluble salt migration as much as 30 to 60 cm into soil overlying drilling fluid after 44 months suggests that burial $\geq$90 cm below the soil surface may be necessary. Increases in plant tissue salt concentrations indicate that uptake of drilling fluid constituents may occur with shallow burial, but heavy metals will not be plant available

under the conditions reported here. Selective-placement burial of drilling fluids will reduce soil contamination on drilling sites, and should facilitate revegetation by natural and/or artificial means.

References

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Table 1. Average soil electrical conductivities at five increments above drilling fluid on the Mertz study site after 20 and 44 months as influenced by depth of burial.

Depth of burial	Time (months) 20	44
(cm)	(dS m^{-1}) (Increment above drilling fluid)	
	(0 to 15 cm)	
30	4.4 a*	24.2 b C
90	8.1	14.5 B
90+barrier	2.6	4.2 A
150	9.2 a	21.0 b C
	(15 to 30 cm)	
30	0.5	0.9 A
90	0.5 a	6.8 b B
90+barrier	0.5	1.3 A
150	1.4 a	14.8 b C
	(30 to 60 cm)	
90	0.4	0.6 A
90+barrier	0.5	0.5 A
150	0.8 a	2.7 b B
	(60 to 75 cm)	
90	0.5	0.5
90+barrier	0.5	0.4
150	0.5	0.6
	(75 to 90 cm)	
90	0.5	0.6
90+barrier	0.5	0.8
150	0.4	0.7

*Means within a depth of burial and row followed by similar lower case letters and within an increment above drilling fluid and colum followed by similar upper case letters are not significantly different by LSD ($P \leq 0.05$).

Table 2. Average soil electrical conductivities at five increments above drilling fluid on the Weatherby study site after 20 and 44 months as influenced by depth of burial.

Depth of burial	Time (months)	
	20	44
(cm)	(dS m^{-1})	
	(Increment above drilling fluid)	
	(0 to 15 cm)	
30	19.5	23.6
90	21.1	21.0
90+barrier	10.6	16.4
150	14.2	20.6
	(15 to 30 cm)	
30	4.3	10.0
90	5.2	37.3
90+barrier	3.4	8.2
150	2.7	17.4
Mean	3.9 a*	18.2 b
	(30 to 60 cm)	
90	0.7 a	5.7 b B
90+barrier	1.0	1.6 A
150	0.9 a	4.2 b B
	(60 to 75 cm)	
90	0.4	0.7
90+barrier	0.5	0.8
150	0.7	0.8
	(75 to 90 cm)	
90	0.5	0.7
90+barrier	0.5	0.6
150	0.9	0.7

*Means within a depth of burial and row followed by similar lower case letters and within an increment above drilling fluid and colum followed by similar upper case letters are not significantly different by LSD ($P \leq 0.05$).

Table 3. Average exchangeable sodium percentages (ESP) at five increments above drilling fluid on the Mertz study site after 20 and 44 months as influenced by depth of burial.

Depth of burial	Time (months)	
	20	44
(cm)	(%)	
	(Increment above drilling fluid)	
	(0 to 15 cm)	
30	7.1	15.4
90	7.1	14.9
90+barrier	1.9	4.9
150	6.6	19.1
Mean	5.7 a*	13.6 b
	(15 to 30 cm)	
30	0.6	0.7 A
90	0.9 a	5.1 b B
90+barrier	1.1	0.9 A
150	1.8 a	6.9 b B
	(30 to 60 cm)	
90	0.8	1.1
90+barrier	1.5	1.2
150	2.0	1.9
	(60 to 75 cm)	
90	0.6	0.5
90+barrier	1.3	1.5
150	1.8	2.1
	(75 to 90 cm)	
90	0.5	0.6
90+barrier	0.7	0.7
150	1.2	1.0

*Means within a depth of burial and row followed by similar lower case letters and within an increment above drilling fluid and colum followed by similar upper case letters are not significantly different by LSD ($P \leq 0.05$).

Table 4. Average canopy cover and biomass production of fourwing saltbush and buffalograss transplants 41 months after planting on the Mertz and Weatherby study sites as influenced by depth of drilling fluid burial.

Depth of burial	Mertz study site		Weatherby study site	
	Saltbush	Buffalograss	Saltbush	Buffalograss
(cm)				
	Canopy cover (%)			
Control	22 a*	6	32 a	12
30	45 b	10	76 b	14
90	64 c	16	62 b	24
90+barrier	62 c	14	65 b	23
150	60 c	20	67 b	24
	Biomass (kg ha^{-1})			
Control	1749 a	115	4184 a	301
30	12822 b	101	16464 b	226
90	17884 bc	231	11450 b	555
90+barrier	18826 bc	381	13000 b	345
150	21501 c	372	12433 b	278

*Means within a parameter and column followed by similar lower case letters are not significantly different according to Duncan's new multiple range test ($P \leq 0.05$).

Table 5. Concentrations of Na, K, Ca and Mg in fourwing saltbush and buffalograss tissue 41 months after planting on the Mertz and Weatherby study sites as influenced by depth of drilling fluid burial.

Depth of burial	Mertz study site			Weatherby study site		
	Fourwing saltbush			Fourwing saltbush		
	Leaf	Stem	Buffalograss	Leaf	Stem	Buffalograss
(cm)	(gkg^{-1})					
	(Na)					
Control	0.02 a*	0.04 b	0.03	0.11 ab	0.03	0.03 a
30	0.01 a	0.02 a	0.05	0.14 b	0.04	0.07 b
90	0.01 a	0.02 a	0.04	0.09 a	0.03	0.05 ab
90+barrier	0.01 a	0.02 a	0.04	0.10 ab	0.03	0.05 ab
150	0.01 a	0.02 a	0.04	0.08 a	0.03	0.04 a
	(K)					
Control	44.6 a	12.8	3.5	45.6 a	16.3	4.4
30	52.3 ab	12.5	3.7	63.7 b	16.1	3.9
90	61.6 bc	13.7	3.7	60.5 b	15.6	4.3
90+barrier	60.3 bc	13.8	3.7	59.2 b	18.1	4.7
150	63.7 c	12.6	4.3	61.8 b	16.6	4.4
	(Ca)					
Control	36.9 b	10.2	7.7	35.3 b	8.4 c	8.8
30	23.6 a	5.7	8.3	21.4 a	5.2 a	14.0
90	22.0 a	5.3	8.5	21.2 a	5.3 ab	11.6
90+barrier	19.5 a	5.3	8.5	24.7 a	6.6 b	11.5
150	22.5 a	4.8	7.7	20.3 a	5.3 ab	13.2
	(Mg)					
Control	6.6	2.0	1.3	9.9 c	2.5	1.1
30	7.1	1.7	1.3	7.5 a	2.0	1.6
90	6.6	1.7	1.4	8.6 ab	2.1	1.3
90+barrier	6.1	1.7	1.1	9.0 bc	2.4	1.4
150	6.4	1.6	1.2	10.0 c	2.3	1.5

*Means within an element and column followed by similar lower case letters are not significantly different according to Duncan's new multiple range test ($P \leq 0.05$).

AN EVALUATION OF THE AREA OF REVIEW REGULATION FOR CLASS II INJECTION WELLS*

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Introduction

As part of regulations promulgated under the Safe Drinking Water Act of 1974, as amended in 1980, the Environmental Protection Agency (EPA) implemented a program to address potential contamination resulting from underground injection practices in the oil industry. EPA mandated that owners and operators of Class II injection wells must locate all wells within an "Area of Review" (AoR) around each injection well being permitted. Class II injection wells are used in the oil field in conjunction with production wells, either for disposal of produced water or for enhanced recovery. Wells within this AoR that represent potential conduits for contamination of underground sources of drinking water (USDW) must be properly plugged by the owner or operator. Although the size of the AoR conducted theoretically depends on reservoir characteristics and the potential for contamination of a USDW, the de facto standard AoR radius for Class II wells is 1/4 mile.

The EPA originally proposed regulations requiring an AoR action for all Class II injection wells, including those that existed prior to the effective date of the regulation, April 1982. Preliminary analyses suggested that this regulation would impose a significant economic burden on the oil and gas industry, in contravention of the Safe Drinking Water Act. Consequently, the EPA modified the regulation to require an AoR study only for those wells that began injecting after the establishment of the state primacy program, April 1982. The rationale for this modification was that as existing fields were developed, the AoR coverage of new wells would eventually encompass the AoR coverage of

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pre-primacy wells. Thus, in the long run, the exemption would not materially reduce the protection of USDWs provided by the original regulation.

This paper presents an approach for the evaluation of two characteristics of the Area of Review provision, the exemption of pre-primacy Class II wells from the regulation and the effect of the size of the AoR. Our objectives in this evaluation are to:

- estimate the impact of the exemption on the effectiveness of the regulation for a randomly-drawn sample of oil fields in Texas;
- identify substitute measures for predicting this effectiveness using a less data-intensive methodology;
- generate statewide and national estimates of the impact of the exemption, using the alternative methodology;
- project the effectiveness of the regulation over time; and
- assess the consequences of changes in the radius of the AoR.

Study Sample and Database

The AoR regulations apply to the surface area of a field. However, fields are often stacked so that several producing zones (each called a field in this paper and by the Texas Railroad Commission) reside under a common surface area. The appropriate unit of analysis, therefore, is the stack. All injection wells for all fields in a stack need to be considered together since the AoR regulations apply to the common surface area. Specifically, the corrective action sometimes required under the regulation may apply to any well that penetrates production zones around the one being reviewed. Unfortunately, records are kept for individual fields rather than stacks and there is no easy way to identify which fields combine to form a stack. Consequently, the sample must be drawn at the field level and then enlarged by other fields that form stacks with the fields drawn for the sample.

At the time we drew our sample, there were approximately 6,500 oil and gas fields in Texas with at least one Class II injection well. Fields that contained no pre-1982 injection wells (2,004) are irrelevant to this study (since the exemption under evaluation is not applicable for these fields) and were excluded from the sampling universe. An additional 3,035 fields contained no post-1982 injection wells; these fields are relevant to this effort since they have wells that benefitted from the exemption. While they must be taken into account in estimating the statewide impact of the regulation, they can safely be excluded from the sampling universe. This leaves 1,455 fields with at least one pre- and post-1982 injection well from which to draw the sample; these fields contained 34,787 pre-1982 and 14,410 post-1982 Class II wells.

From this universe, we drew a random sample of 200 fields using an inventory provided by the Texas Railroad Commission (TRRC). Twenty five fields were eliminated due to missing data at the well level (primarily missing API well numbers). The 175 remaining fields were evaluated individually to determine if they belonged to a stack; other fields from the same formation (generally identified by similar names but different producing depths) were added to the

sample. The final sample, after expansion, consisted of 402 fields in 175 stacks, containing 9,840 Class II wells.

The sample was stratified along three dimensions: geography, size, and type of injection activity. Geography was assumed to be an important stratification variable because it reflects geologic and historical variables that are important determinants of past and future injection activity (e.g., discovery date, reservoir depth, basin). The geographic units used for stratification were TRRC districts because no records are kept by oil basin. Once fields were selected, however, they were plotted on geologic maps to identify which of the seven major Texas basins they belonged to. Three size categories were used, based on the total number of injection wells in each field; the ranges were two to ten, 11 to 40, and over 40. Size was deemed an important stratification variable because it reflects the likelihood of further injection activity and because it influences the effectiveness measures eventually selected. Finally, the type of injection activity is important because disposal and enhanced recovery imply very different well-siting patterns. Disposal wells are often located on the edges of fields while secondary recovery wells tend to be spaced regularly around production wells within the production outline of the field. Exhibit 1 provides details on the number of fields in the sample by stratification category.

Exhibit 1: Sample Stratification

		2 to 10 wells			11 to 40 wells			> 40 wells		
TRRC DIST	FIELD SAMPLE	NO DISPOSAL	BOTH	NO ENHANCED	NO DISPOSAL	BOTH	NO ENHANCED	NO DISPOSAL	BOTH	NO ENHANCED
01	10	2	2	1	1	2	0	1	1	0
02	12	0	3	4	0	2	0	0	0	0
03	20	0	4	6	0	6	1	0	2	0
04	19	3	4	4	2	4	0	0	2	0
05	4	0	2	1	0	1	0	0	0	0
06	11	2	3	1	1	4	0	0	1	0
6E	1	0	0	0	0	0	0	0	1	0
7B	28	7	8	2	3	4	0	1	2	0
7C	12	3	3	1	2	2	0	1	1	0
08	30	4	5	1	5	4	0	6	9	0
8A	24	3	5	1	3	5	0	1	7	0
09	24	5	6	1	3	4	0	1	1	0
10	5	0	1	1	0	1	0	0	1	0
	200	30	45	23	22	38	1	12	29	0

It is important when sampling to assure that the sample selected is representative of the universe. This turns out to be largely true for this

study. About 71 percent of injection wells in the 1455 fields from which the sample was drawn were pre-1982 wells; about 91 percent of injection wells in these fields were used for secondary recovery. For the sample, the percentages were 66 percent and 89 percent, respectively. Evaluation of the stratification by size suggests that large (>40 wells) and medium (11-40 wells) fields are over-represented, (21 percent in the sample against 13 percent in the universe, 31 percent in the sample against 21 percent in the universe, respectively). This bias is not particularly disturbing since small field effectiveness measures are subject to great variations due to the small number of wells. It is impossible to evaluate the geographic representation of fields since there exists no central source for the distribution of fields by basin for the universe.

Once the fields were selected, we used the TRRC Underground Injection Control data tape to create a well-level database with each injection well's API number. Other elements of this database are the type of injection, the date of permit approval, the operator and lease identifiers, and location and survey data. Latitude and longitude data for each well were obtained separately from a commercial vendor and merged with the well-level database. Because we use computerized mapping to permit the evaluation of our large sample, accurate location data is critical to this study. We relied on matching API well numbers; this procedure was successful for 86 percent of the 9,840 wells in our sample. For some of the remaining wells, it was possible to compute latitude and longitude by using survey, block, and section location data off of the UIC data tape. This was not feasible in all cases; consequently the effectiveness measures for some field will incorporate a bias. The direction of this bias will depend on whether the missing location data applies to pre- or post 1982 wells.

A second, stack-level database was also created for the regression analysis discussed later. Details about the variables of this database are presented in a subsequent section.

Measures of Effectiveness

The ideal method for evaluating the implication of the exemption is to compare well counts for the pre- and post-82 AoR's in each field in the sample. Then, it is possible to assess directly the number of wells that would be excluded from review and estimate the scope of the potential contamination problem. However, data on well counts are unobtainable except through the conduct of AoRs; this is clearly not feasible for this study and some proxy measure of effectiveness must be devised. In this paper, we consider two measures of surface area as our proxies, overlap and percentage of production outline covered.

By its nature, AoR is a surface area concept. While the effectiveness of the regulation depends on both its design and its implementation, we concern ourselves here only with the former. This means that we can approximate the coverage of the regulation for a particular field by estimating how much of the pre-1982 well AoRs area has or will be covered by the AoR areas of injection wells permitted after April 1982. This is our first measure, which we term

"overlap". Formally, it is the ratio of the intersection of pre- and post-1982 AoR areas to the pre-1982 AoR area:

$$\text{Overlap} = \frac{\text{intersection of pre- and post-1982 AoR areas}}{\text{pre-1982 AoR area}}$$

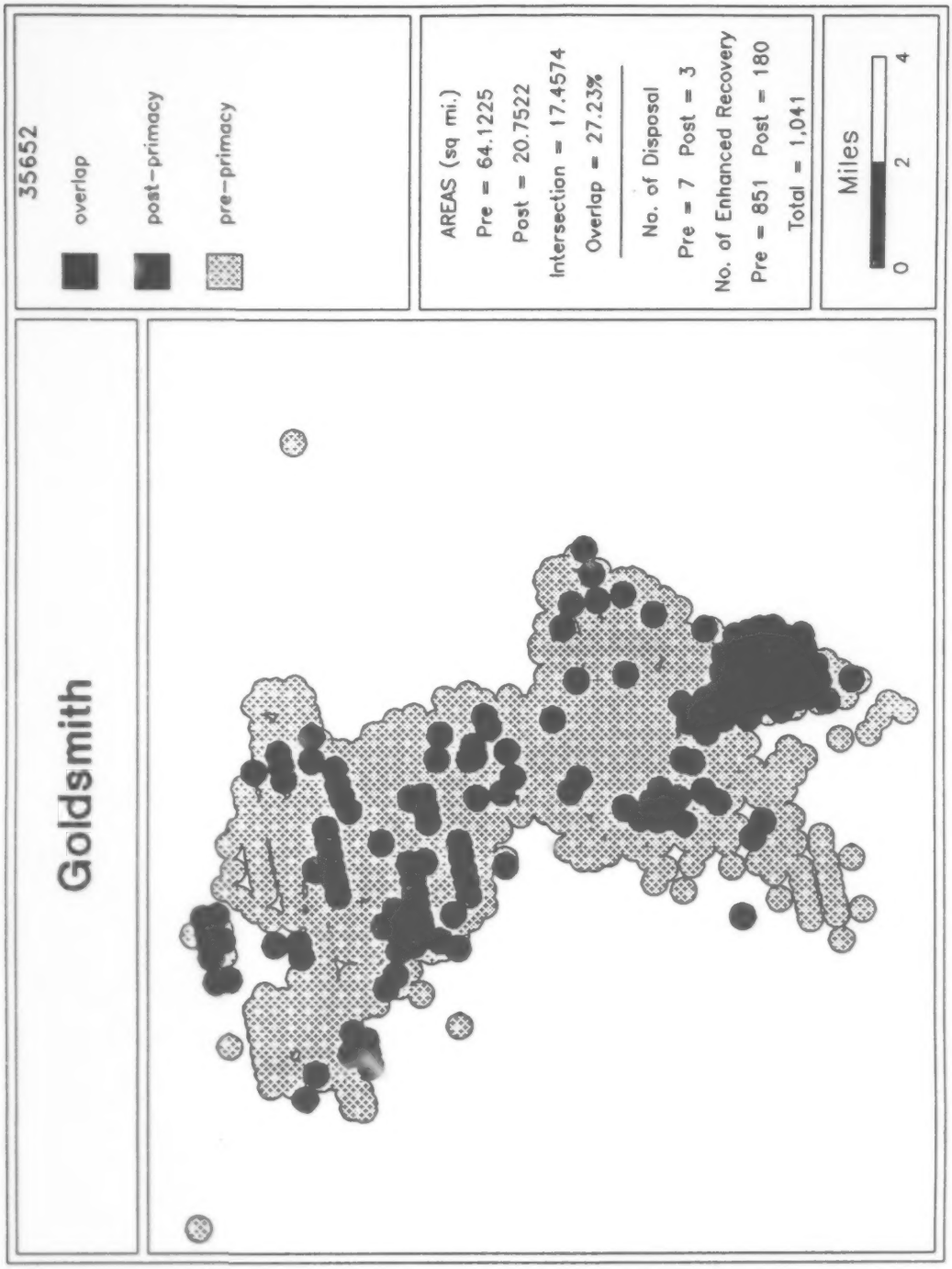
The higher the ratio, the greater the degree of coverage by post-1982 wells and the lower the "cost" of the exemption of pre-1982 wells from the regulation for any particular field. Overlap is only an indirect measure of this cost in the sense that it is not readily convertible to a measure of potential risk to USDWs. With additional assumptions and information about the relationship between field and operator characteristics and the presence of abandoned wells, this overlap percentage could be used for a more explicit assessment of contamination risk.

A second, more general, measure of the effectiveness of the AoR regulation is the percentage of the surface area of the field covered by the AoR of post-1982 injection wells. Unfortunately, the surface area of a field is not readily available. Moreover, since the unit of analysis is the stack, the surface area over the stack must be computed as the union of the areas of all fields in the stack. This measure is impossible to obtain. We use instead an approximation of the production outline of the stack as the base surface area. This approximation is generated by first imposing the well spacing guideline for the field on each plotted injection well and taking the outer envelope of the areas around all wells in the stack. The area of the resulting polygon is then calculated and used as the base surface area. Formally, the "coverage area" is:

$$\text{Coverage Area} = \frac{\text{area of post-1982 AoRs}}{\text{area of production outline}}$$

Both measures are obtained for each stack in the sample using Atlas GIS software. To compute overlap, the program first plots each pre-primacy well in a stack, using latitude and longitude coordinates obtained from the database. It then draws the AoR radius around each well and calculates the sum of the AoR areas. This is recorded as the denominator of the overlap measure. It then plots all the post-primacy wells permitted in 1982, draws the appropriate AoR radius around each, and identifies the intersection of the pre- and post-primacy polygons. This area is the numerator of the overlap measure for 1982. The program repeats this procedure for each year that injection wells were permitted in this stack. The outcome is an annual cumulative overlap measure for the period April 1982 to April 1990. An illustration of the overlap measure for a field in the sample is presented on the next page as Exhibit 2. To compute coverage area, the program first plots all injection wells, defines areas around each well based on well spacing rules, and defines a polygon whose perimeter is the outer boundary of the areas around all wells. This is the area of the production outline, the denominator of this measure. It then draws the appropriate AoR radius around post-primacy wells and computes the area of

Exhibit 2: Overlap Calculation



this polygon. This is recorded as the numerator of the coverage area measure and it can also be computed cumulatively.

With this database and software, it is relatively easy to assess the impact of changes in the AoR radius. In this paper, we consider the standard 1/4 mile radius and an alternative 1/2 mile radius.

Cross-sectional Study of the Determinants of Overlap

The methodology developed and discussed above represents a considerable improvement over manual plotting and paper map evaluations. It could easily be extended from our sample of Texas fields to include a representative national population except for data availability and acquisition costs. Well-specific latitude and longitude data, for example, are prohibitively expensive if they are available at all. In this section, we discuss the use of regression analysis to identify predictive measures of overlap that could provide national estimates without the expense of collecting well-specific data.

Regression analysis attempts to explain the variance in a dependent variable by attaching weights to independent or explanatory variables. In this application, the dependent variable is the overlap measure presented above. The explanatory variables are stack-specific characteristics that are considered, *a priori*, to have potential for affecting the dependent variable. In general, these might be categorized as geologic, productive, and institutional. Because this is a cross-sectional study (in which we attempt to account for differences across stacks), we take only the cumulative overlap as of April 1990 as our dependent variable. We can also ignore explanatory variables that would affect overlap over time; these are largely economic in nature (such as oil prices). They are treated in the next section.

Geologic variables reflect the relationship between reservoir characteristics and the likelihood of undertaking secondary recovery or disposal activities. These might include reservoir porosity, permeability, and depth. Productive variables attempt to explain differences in overlap across fields on the basis of industry behavior. These might include the discovery date, the ratio of pre- to post-primacy wells, the ratio of disposal to enhanced recovery wells, and the number of operators working the stack. Institutional variables account for the impact of regulations; typical of these are well spacing rules that govern the minimum distance between production wells and unitization rules.

To conduct this analysis, we created a separate stack-level database that consisted of the overlap measure previously calculated for each stack and the independent variables listed above. This database is used to regress overlap on the set of explanatory variables, using ordinary least squares (OLS) techniques. The procedure yields a series of weights to be attached to each independent variable, along with statistics on the "goodness of fit" of the entire model and the statistical significance of each variable. Preliminary tests with a small subsample of Texas fields suggest that there is a high degree of fit of the model and that well spacing, the age of the field, and the ratio of disposal to enhanced recovery wells are significant explanatory variables. If

this finding obtains with the full sample, it implies that reliable national estimates of current overlap could be obtained without expensive well-location data.

Longitudinal Study of the Determinants of Overlap

The AoR concept is dynamic, meaning that it is intended to achieve its goals over time. The cross-sectional analysis discussed above is static, meaning that it attempts to explain overlap at a single point in time. While the latter is useful for identifying certain predictors of overlap, a true evaluation of the effectiveness of AoR should consider what is likely to happen in the future.

To address this issue we add four economic variables to the stack-level database discussed in the previous section. These new explanatory variables treat the price of oil, the tax policy affecting oil production, and the type of operator working the stack.

It is safe to assume that operators respond to price changes in determining the rate of oil extraction; one way in which they may vary production levels is through secondary recovery. Therefore one would expect that oil prices would affect overlap over time. In reality, however, there is a lag between price changes and production changes, so the proper independent variable to use is lagged prices. A second way in which oil prices may influence the decision to undertake secondary recovery reflects the uncertainty about future prices. When prices fluctuate a great deal in a short time, operators will be less certain about their future price expectations and will be more hesitant to invest in additional production. To proxy this uncertainty about future prices, we use the variance in prices over three and five year horizons. The extant tax policy is another important economic determinant of the level of investment by oil and gas firms. Since the 1970's, a number of provisions of the tax code directly affecting these firms have been eliminated or modified (e.g., the windfall profits tax, the oil depletion allowance, corporate tax rates). To account for the potential impact of these tax rules, we use dummy variables to indicate their presence over time. Finally, the characteristics of the operator should be helpful in predicting secondary recovery activity and thus the development of overlap over time. Different firms have different capital constraints and capital costs; different firms also have varying levels of technological sophistication and available engineering resources. Since these factors will all influence the timing of secondary recovery projects, it is important to consider them in this longitudinal model. We greatly simplify these operator characteristics by classifying firms into one of three categories, major, independent, and minor, on the assumption that firms of similar size will behave similarly with respect to the factors just discussed.

Aside from these additions to the set of explanatory variables, we must also consider a different dependent variable for the longitudinal analysis, the annual change in overlap for each stack. Because a single incremental change in overlap measure for the sample (such as a weighted average) is meaningless, we have to resort to a panel data analysis (which combines cross-sectional and longitudinal data). The database now consists of nine observations per stack

(one for each year of the 1982-1990 sample period). The objectives of this analysis are essentially the same as those of the pure cross-sectional analysis although the choice of method and test statistics will differ. We still look to identify those variables that are significant in explaining the growth in overlap through time.

The last step of the analysis is to estimate overlap for several years into the future. This requires the adoption of a scenario for each significant variable identified by the econometric work briefly discussed in this section. If, for example, lagged oil prices are significant predictors of overlap changes, an assumption about a future oil price path will have to be made. By combining likely scenarios for all the significant explanatory variables, a range of probable outcomes for future overlap can be generated and the "cost" of the exemption of pre-1982 wells derived.

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EVALUATION OF THE GROUNDWATER CONTAMINATION POTENTIAL OF ABANDONED WELLS BY NUMERICAL MODELING

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ABSTRACT

A detailed study has been made of the characteristics of abandoned oil and gas wells in the Lower Tuscaloosa Sand trend of Mississippi and Louisiana and their potential as conduits for movement of saline water from the Lower Tuscaloosa into underground sources of drinking water (USDW's).

The study included correlation of the stratigraphic units throughout the Lower Tuscaloosa trend; documentation of the engineering characteristics of geologic units and of abandoned wells in the trend and estimation of the thickness, porosity and permeability of drilling mud and sloughed shale in abandoned wells in the trend. Also, although breach of casing by corrosion is considered unlikely in this region, the location of the stratigraphic interval most susceptible to corrosion was established.

After assembly of the data listed above, finite difference numerical modeling was performed to determine the extent to which water might be forced from the Lower Tuscaloosa Sand into an USDW as a result of injection into the Lower Tuscaloosa. Within the range of conditions that were modeled, water from the Lower Tuscaloosa was found never to travel into an USDW. These conditions included the two scenarios of an abandoned uncased well with a column of settled sloughed shale and settled mud solids in the borehole and of a cased well with corrosion of casing in the lower Wilcox Formation and with sloughed shale and settled mud solids in the casing-tubing annulus.

The procedures developed in this study should be readily applicable to the analysis of the potential for abandoned wells to act as pathways for contaminant flow into USDW's in other oil and gas producing areas of the country.

INTRODUCTION

Purpose and Scope of Study

Because of increasing focus by regulatory agencies upon abandoned oil and gas wells, the University of Missouri-Rolla has conducted research for assessment of the potential for abandoned oil and gas industry wells in the Lower Tuscaloosa Sand oil producing trend of Mississippi and Louisiana to act as conduits for flow of saline water from the Lower Tuscaloosa Sand into underground sources of drinking water.

The locations of selected wells from oil fields in the Lower Tuscaloosa Sand trend are shown in Fig. 1. As can be determined from the lines of the cross sections formed by the wells (see footnote), the Lower Tuscaloosa Sand trend extends for about 135 miles from south-central Mississippi northwestward into eastern Louisiana and for about 100 miles from north to south.

The study included the assembly of the geologic and engineering data necessary to formulate numerical models that would allow simulation of the range of flow conditions through abandoned wells in the Lower Tuscaloosa trend. The final step in the study was the actual numerical simulation of flow conditions for such abandoned wells.

Previous Work

The first numerical modeling work known to the authors with respect to the movement of fluids through an abandoned well was that carried out by Ward, *et al.(2)* in which the leakage of injected contaminants through an abandoned unplugged borehole was modeled. The problem here is different, in that it involves tracking of the movement of native saline water from a saline-water bearing aquifer into a nearby abandoned well in response to the pressure created by an injection well.

Warner(3) modeled the response of a specific existing abandoned well in the West Mallalieu oilfield to injection through a nearby water-injection well. An analytical model of the abandoned well problem was developed by Javendel, *et al.*(4)

STATEMENT OF THE ABANDONED WELL PROBLEM

Many thousands of wells have been drilled and abandoned during the 130 year history of the U.S. petroleum industry. Regulations for plugging of such wells were nonexistent in the early days of the industry and have evolved, over the years, to their present effective level. Thus an unknown but large number of abandoned wells exist that may be unplugged or inadequately plugged by today's standards.

The cross sections are not contained in this paper but are available in Ref. 1.

As a result of incidents in which abandoned wells have been implicated as sources of ground water contamination, such wells are often considered, without discrimination among them, to be potential pathways for contamination of an underground source of drinking water (USDW). Such contamination can result from interaquifer flow of natural formation water or by transmission of injected fluids from the injection reservoir to an USDW.

In fact, the relative contamination potential of such wells ranges from highly likely to impossible, depending on a complex set of well factors and geologic and hydrologic circumstances. The relative contamination potential of an abandoned well or wells in a particular geologic and hydrologic setting can be first analyzed qualitatively by an understanding of the factors involved. Warner(5) has listed and discussed, at length, those factors which include well age, well depth, well type, well construction, well plugging and abandonment history and the hydrogeologic conditions at the well site.

In instances where an abandoned well does have possible pathways through which natural brines or injected fluids could migrate to USDW's and where the hydrogeology is also amenable to such interaquifer flow, then quantitative analysis with numerical computer models may be a useful means of predicting whether or not such interaquifer flow is likely to occur. This report documents the processes of both qualitative and quantitative evaluation of abandoned oil and gas wells in the Lower Tuscaloosa trend of Mississippi and Louisiana.

GENERAL DESCRIPTION OF NUMERICAL MODEL

Modeling for this research project was carried out using the SWIFT III numerical code. SWIFT III(6) is a revised and improved version of a code originally developed for the U.S. Geological Survey specifically for injection well modeling. SWIFT III is the result of more than 10 years of model evolution. The original model acronym, SWIP, stood for (U.S. Geological) Survey Waste Injection Program. SWIFT is the acronym for Sandia Waste-Isolation Flow and Transport Model. The original documentation for SWIP was presented by Intercomp(7). This was followed by SWIPR(8), SWIFT(9), SWIFT II(10,11) and SWIFT III(6).

The SWIFT code is a fully transient, three-dimensional finite difference numerical code that solves the coupled equations for fluid flow, transport of chemicals that do not decay radioactively, transport of radionuclides and heat transport. According to Prickett, *et al.*(12) the SWIP (or SWIFT) type models represent the latest in such numerical models and are the most comprehensive ones available.

GEOLOGY AND PETROLEUM PRODUCTION IN THE LOWER TUSCALOOSA TREND

Fig. 2 depicts a generalized stratigraphic column of the Mallalieu Field, Lincoln County, Mississippi. Strata shown in Fig. 2 range in age from the Cretaceous Lower Tuscaloosa Sand at the base to the Eocene Cook Mountain and

Sparta Sand units at the top of the column. At the Mallalieu Field and elsewhere in southern Mississippi and in southeastern Louisiana, strata of Oligocene through Holocene age overlie the Cook Mountain and Sparta.

The only geologic unit that has produced oil or gas in the study area is the Lower Tuscaloosa Sand. This fact is of great practical importance, since it means that there are no younger and shallower or deeper and older producing units in the many Lower Tuscaloosa fields into which oil or gas producing wells have been drilled and abandoned. This fact considerably limits the possibilities of interaquifer flow through abandoned wells, since it is not necessary to be concerned about any significant number of such wells other than those specifically drilled to the Lower Tuscaloosa Sand.

The fact that the Lower Tuscaloosa is the only producing formation also restricts the manner in which wells have been drilled, completed and abandoned. Lower Tuscaloosa oil production began in the early 1940's and fields are now in the very late stages of petroleum recovery. The Mallalieu and Little Creek fields are, for example, undergoing tertiary oil recovery by injection of carbon dioxide. Because drilling in the Lower Tuscaloosa trend did not start until the 1940's the technology and regulation of well construction and abandonment had already advanced considerably over that practiced in the early 1900's. The actual practices used will be covered in the next section.

Cross sections that were developed for the study(1) show correlation of the strata throughout the Lower Tuscaloosa oil producing trend. While all of the geologic units of interest are different in thickness and in lithologic detail in any one of the oilfields for which a log is shown, the section as it occurs in the Mallalieu Field is as representative as any that could be selected. Therefore, the stratigraphic section for the Mallalieu Field, as shown in Fig. 2, was selected for modeling purposes.

Uncased Well Scenario

The conditions of the uncased well scenario are shown in Fig. 3. This scenario is very straightforward in that surface casing has been typically set to about 1,400 - 1,500 ft [427 - 457 m] of depth and cemented to the surface. The remainder of the hole needed to reach the Lower Tuscaloosa Sand is left open until the Lower Tuscaloosa has been reached and its thickness and production capability assessed. If the Lower Tuscaloosa Sand is present and sufficiently thick and promising of production, the well is cased. If the Lower Tuscaloosa Sand is missing or thin or otherwise likely to be uneconomically productive, the well is plugged and abandoned with the drilling mud in the hole and with no casing other than the surface casing. Many such abandoned wells do contain cement plugs. However, in the worst case, a well might not contain anything other than drilling mud upon abandonment. That was the scenario selected to be modeled.

Cased Well Scenario

When a Lower Tuscaloosa Sand well is drilled and the sand is found to be present and judged likely to be sufficiently productive, the well is cased with production casing through the Lower Tuscaloosa (Fig. 4). The production casing is cemented at the bottom with about 2,000 ft [610 m] of cement. The remainder of the annulus behind the production casing is left mud filled.

Of course, if the casing were to remain intact, there is no possible threat to groundwater resources. It is possible, however, that the casing could become corroded to the extent that it would be breached and a pathway to formations behind the casing would exist. If corrosion were to occur, it was judged most likely to be in the lower portion of the Wilcox Sand(13) where injection of brines could render the water more corrosive. An arbitrary depth of 6,000 ft [1830 m] was selected as the possible location of such a corroded interval of casing.

WELLBORE PROPERTIES OF SETTLED MUD SOLIDS AND FORMATION MATERIALS

Through procedures described in Ref. 1, it was calculated that, in the uncased well scenario, a 154.5 ft [47 m] thick column of sloughed shale would be present at the bottom of the hole and that would be overlain by a 4,620 ft [1409 m] column of settled mud solids (Fig. 3). The porosity of the sloughed shale column was assumed to be that of the in-place material or 3%. The permeability of the sloughed shale was assumed to be 0.1 md. The porosity of the settled mud solids column was assumed to be 84% and its permeability to be 1.0 md. The rationale for those values is contained in Ref. 1.

In the cased well scenario, a cement sheath extended from bottom hole to 8,500 ft [2591 m]. A sloughed shale column 200 ft [61 m] thick was calculated to be present on top of the cement and a settled mud column 3,740 ft [1140 m] thick on top of the sloughed shale (Fig. 4). The sloughed shale and mud solids were assumed to have the porosity and permeability values given above for the uncased well scenario.

MODELING OF TWO REGIONAL SCENARIOS

Uncased Well Scenario

A three dimensional 47 node x 20 node x 10 layer model grid was designed for simulation of the uncased well scenario. Because the geologic units were treated as if they were homogeneous and infinite in areal extent, the flow field was symmetric and only half of the grid was present in the Y dimension. The injection well and the abandoned well were located 500 feet apart and roughly centered along the X boundary. The X-Y extent of the grid was 10 x 10^5 by 9 x 10^5 ft [3 x 10^5 by 2.7 x 10^5 m] and was established by trial and error to be large enough so that no significant boundary effects would occur during the 10-year modeling period.

The 10 model layers used in the vertical or Z dimension are shown in Fig. 3. Table 1 lists the values for the model parameters used in simulation runs for the uncased abandoned well scenario.

Representative simulation results for the Uncased Well Scenario are shown in Table 2. Table 2 lists the ΔP at the bottom of the injection well (bottom hole pressure or BHP), the ΔP at the bottom of the abandoned well, the rate of flow of saline water into the ground water zone (USDW), the rate of flow into the abandoned well and the rate of flow into the Upper Tuscaloosa.

To study the effect of the maximum likely injection rate on flow up the abandoned well and into the upper Tuscaloosa the simulation of Table 2 was performed with an injection rate of 600 bbl/d and an injection zone permeability of 30 md. The simulation showed no flow into the USDW zone at the 600 bbl/d injection rate. Flow rates of less than 10^{-2} bbl/d should be considered so small as to be highly inaccurate. For practical purposes, such rates indicate that no measurable flow is occurring.

Cased Well Scenario

A three dimensional 48 node x 22 node x 12 layer model grid was designed for simulation of the cased well scenario. Because the geologic units were treated as if they were homogeneous, isotropic and infinite in areal extent, the flow field was symmetric and only the upper half of the grid was present in the Y dimension. The injection well and the abandoned well were 500 feet apart and roughly centered along the X boundary. The X-Y extent of the grid was 3.4×10^5 by 2.1×10^5 ft [1×10^5 by 6.4×10^4 m] and was established by trial and error to be large enough so that no significant boundary effects would occur during the 10-year modeling period.

The 12 model layers used in the vertical or Z dimension are shown in Fig. 4. The layers were selected to discriminate the hydrogeologic units and, also, the cement, the sloughed shale and the settled mud layers behind the casing and the interval of corroded casing. Table 3 lists the values for the model parameters used in simulation runs for the cased abandoned well scenario.

Representative simulation results for the Cased Well Scenario are shown in Table 4. The flow of saline water vertically from the Wilcox Formation through the Winona Shale and Cane River Marl and into the USDW was zero for all simulations.

As in the uncased well scenario, flow rates of less than 10^{-2} bbl/d should be considered highly inaccurate. For practical purposes, such rates indicate that no measurable flow is occurring.

CONCLUSIONS

On the basis of the modeling that was performed, it is concluded that it is very unlikely that conditions would ever exist in the Lower Tuscaloosa trend of Mississippi and Louisiana where abandoned oil and gas wells would serve as conduits for movement of water from the Lower Tuscaloosa into an USDW. In the scenario of the uncased well, essentially no water was found to move vertically through the sloughed shale-settled mud column and no measurable amount of that which did penetrate the settled mud column reached the Sparta, which is the USDW in the Mallalieu Field area. In the cased well scenario, essentially no water moved through the settled mud sheath into the Wilcox Formation and none of that water which did flow into the Wilcox moved vertically through the Wilcox and the Winona-Cane River into the Sparta.

The procedures developed in this study should be readily applicable to the analysis of the potential for abandoned wells to act as pathways for contaminant flow into USDW's in other oil and gas producing areas of the country. Modeling is considered to be a very powerful tool for classification of abandoned wells. While such modeling is not a trivial exercise, and the necessary data are not routinely available, the information produced can return the necessary investment many fold by diverting concern where it is unwarranted and, thus, avoiding unnecessary regulatory effort.

ACKNOWLEDGEMENTS

The authors thank the American Petroleum Institute for its financial support for the research documented in the paper. Shell Oil Company commissioned the stratigraphic study of the Lower Tuscaloosa Trend as a separate but essential part of the project. B.E. Esquinance, Shell Offshore Inc., developed the well scenarios described herein. Nina K. Springer, Exxon Production Research Company, developed the methodology for estimating the characteristics of settled mud and sloughed shale in abandoned wells, as used in the study. Ms. Springer also chaired the API Control Issues Group that provided oversight of the study. We express our appreciation to that group for its helpful suggestions and input to the study.

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SI METRIC CONVERSION FACTORS

bbl x 1.589 873 E-01 = m^3

psi x 6.894 757 E+00 = kPa

Table 1. Model Parameters - Uncased Abandoned Well Scenario

Model Layer	K_x and K_y Permeability ($K_z = K_{x/10}$)	Porosity
1	1 darcy	35%
2	2.5×10^{-8} darcy	3%
3	1 darcy	30%
4	1 darcy	30%
5	1 darcy	30%
6	2.5×10^{-8} darcy	3%
7	0.1 darcy	23%
8	2.5×10^{-8} darcy	3%
9	2.5×10^{-8} darcy	3%
10	2 md or 30 md	25%

Permeability	Porosity	
drilling mud	1 md	84%
sloughed shale	0.1 md	
empty borehole	3.7×10^{8} darcies (10^{9} ft/day)	100%

Other Parameters

water compressibility	3×10^{-6} psi^{-1}
rock compressibility	5.5×10^{-6} psi^{-1}
fluid specific weight	67.3 lb/ft^3
viscosity	1 cp

Table 2 - Listing of pressure buildups and flows, with time, for an injection rate of 600 bbd/day and a Lower Tuscaloosa Sand permeability of 30 md, uncased abandoned well scenario

Time (since inj. began)	ΔP (BHP) inj well	ΔP(bottom) abd well	Q(into) USDW	Q(into) abd well	Q(into) upper Tuscaloosa
.01 d	252 psi	0 psi	0 bbl/d	0 bbl/d	0 bbl/d
.1	332.6	0.1	0	0	0
1.0	399.5	6.9	0	1.67×10^{-7}	9.9×10^{-11}
10.0	488.7	63.2	0	6.6×10^{-6}	1.6×10^{-8}
100.0	559.5	130.3	0	3.0×10^{-5}	2.0×10^{-7}
1000.0	640.1	211.5	0	6.6×10^{-5}	6.0×10^{-7}
2000.0	664.4	235.8	0	8.3×10^{-5}	8.1×10^{-7}
3650.0	684.9	256.3	0	1.0×10^{-4}	1.1×10^{-6}

Table 3 - Model Parameters, cased abandoned well scenario, Lower Tuscaloosa Trend

Model Layer	Permeability ($k_x = k_y = k_z$)	Porosity
1	1 darcy	35%
2	2.5×10^{-8} darcy	3%
3	1 darcy	30%
4	1 darcy	30%
5	1 darcy	30%
6	1 darcy	30%
7	1 darcy	30%
8	1 darcy	20%
9	2.5×10^{-8} darcy	3%
10	0.1 darcy	23%
11	2.5×10^{-8} darcy	3%
12	2 or 30 md	25%

drilling mud - 1 md
empty borehole - 3.7×10^{8} darcies (10^{9} ft/day)

Other Parameters

water compressibility	3.6×10^{-6} psi^{-1}
rock compressibility	5.5×10^{-6} psi^{-1}
fluid specific weight	67.3 lb/ft^3
viscosity	1 cp

Table 4 - Listing of pressure buildups and flows, with time, for an injection rate of 200 bbl/day and a Lower Tuscaloosa Sand permeability of 30 md, cased abandoned well scenario

Time (since inj. began)	ΔP (BHP) inj well	Q into abandoned well
.01 d	44.7 psi	0 bbl/d
.1	70.4	0
1.0	84.5	1.6×10^{-5}
10.0	115.8	3.7×10^{-4}
100.0	132.9	7.8×10^{-4}
1000.0	149.5	1.2×10^{-3}
2000.0	154.6	1.4×10^{-3}
3650.0	158.4	1.5×10^{-3}

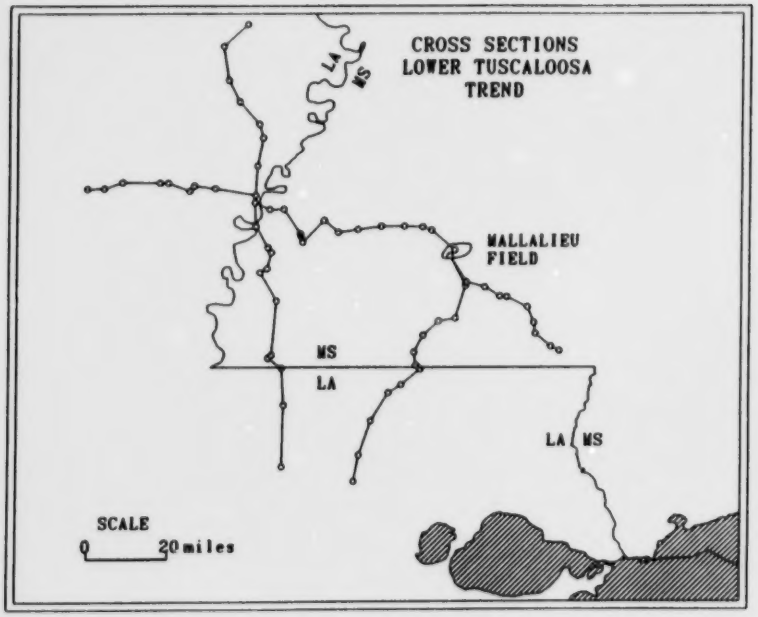

Fig. 1 - Map showing location of wells used in Lower Tuscaloosa Trend study.

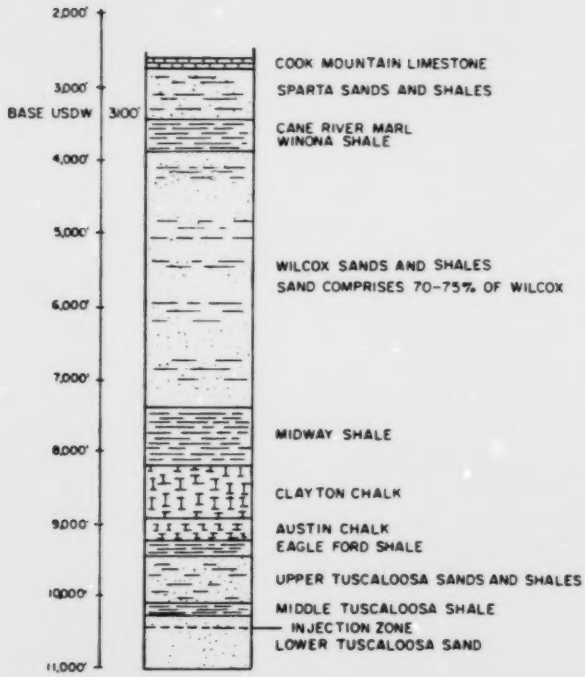

Fig. 2 - Generalized stratigraphic column Mallalieu Field, Lincoln Co., Mississippi.

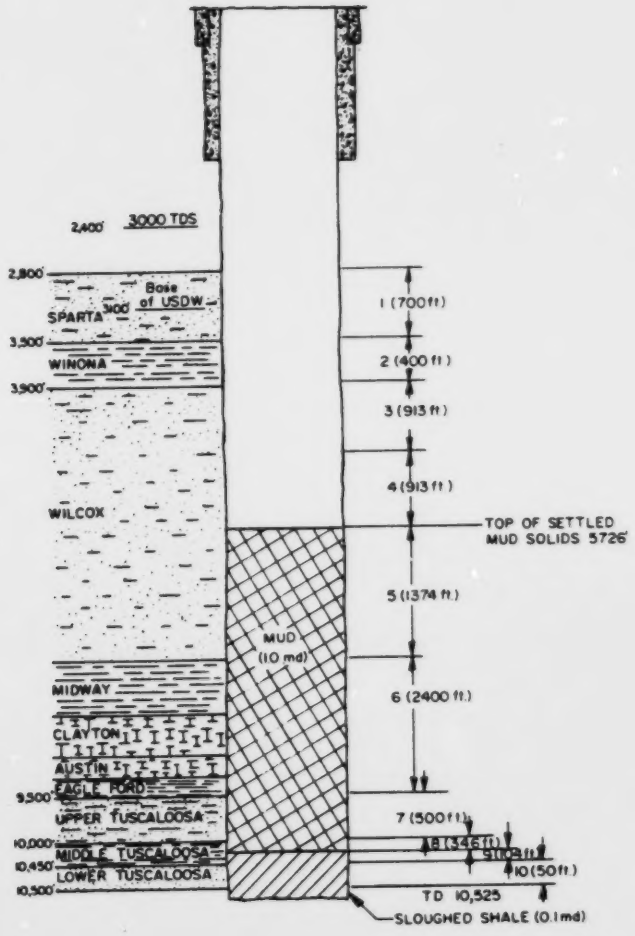

Fig. 3 - Illustration of uncased abandoned well scenario, Lower Tuscaloosa trend, showing finite difference model layers.

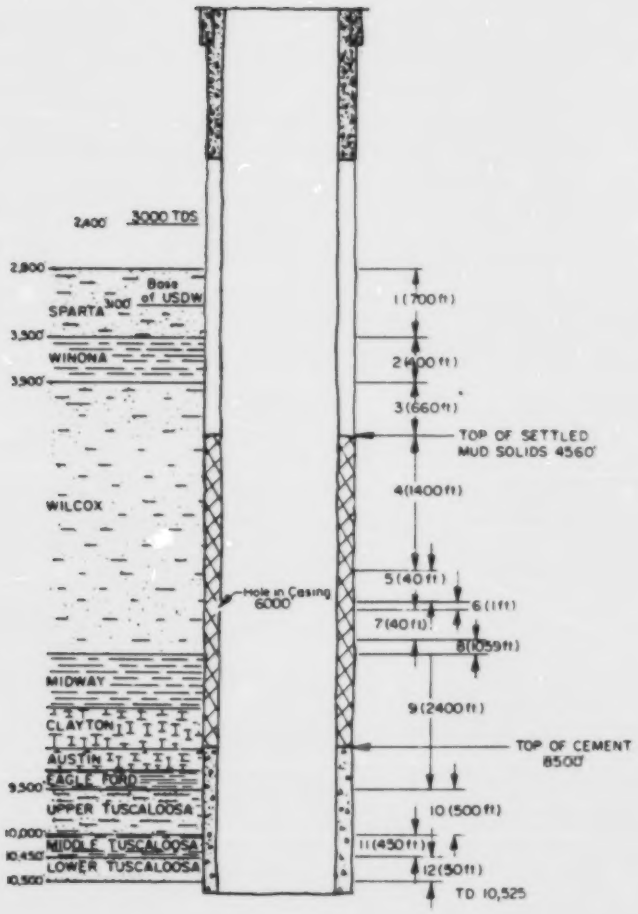

Fig. 4 - Illustration of cased abandoned well scenario, Lower Tuscaloosa trend, showing finite difference model layers.

EVALUATION OF THE USE OF A PIT MANAGEMENT SYSTEM

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Introduction

The ability to effectively manage drilling wastes during the drilling of a well can result in greatly reduced waste disposal costs. Traditional reserve pit designs consisting of a one or two pits do not allow flexibility in managing the drilling wastes. The use of a pit management system consisting of a minimum of four pits allows the operator to segregate the waste and manage its treatment or disposal either during the drilling operation or after completion of drilling.

If any unforseen problems such as drilling into salt, taking a saltwater kick, having to change to a mud system that contains environmental contaminates, or other similar situation, are encountered while drilling using a conventional reserve pit, the only management option is to place the contaminated mud and/or cuttings into the pit and potentially contaminating the entire contents of the pit. If onsite treatment or disposal becomes impossible because of either contamination, problems with annular injection, or other reasons, the cost of disposal increases from a range of $0.30/barrel to $1.00/barrel to as high as $7.00/barrel or more.

This paper utilizes case studies from wells drilled in the central Gulf Coast to evaluate the Pit Management System as compared to the more traditional waste management practices of a conventional reserve pit or a closed system. These case studies compare waste volumes and cost of waste disposal. The results of this study support the use of the Pit Management System.

Concept of the Pit Management System

A traditional reserve pit associated with most onshore drilling operations consists of one large pit into which mud, drill cuttings, wash water, rain water, and other liquid wastes are placed and stored until the end of the drilling operation. Then the waste is analyzed, the water treated and discharged, and the remaining material is either injected into the annulus of the well, buried, landfarmed on site, or hauled to a approved offsite treatment or disposal facility.

Problems with a traditional reserve pit can result when contaminated mud or cuttings are mixed with uncontaminated material in the pit rendering the entire contents of the pit unsuitable for onsite treatment or disposal. This can occur when an operator drills into salt and is forced to place salt cuttings into the pit, when saltwater bearing formations are encountered and the saltwater contaminates the pit contents, or when weighted muds containing barite cause barium contamination of the pit contents. This situation can be extremely costly and can be prevented with a minimum of planning and the construction of a pit system which allows management of the pit contents.

The use of a managed pit system will allow the drilling wastes to be segregated. Relatively uncontaminated materials can be treated or disposed of on site, while the more contaminated wastes can be injected or transported to an offsite commercial disposal facility for treatment or disposal. This can be done either during the drilling operation or at the completion of drilling activities.

The cost of construction and management of the pits is slightly higher than the conventional reserve pit, but is significantly lower than either a closed system or a conventional reserve pit when total haul-off to a commercial facility is required. The case studies presented in this paper show that the cost of treatment/disposal of wastes from a managed pit will range from a low of $0.40/barrel to a high of $1.84/barrel, which is significantly lower than the cost of the closed system which ranged from $2.67 to $7.00/barrel of waste treated.

The Pit Management System consists of a minimum of four pits constructed in the area normally occupied by a conventional reserve pit. Area is also provided for a drag-line to move solids from one pit to another and to remove material from pit

during the drilling operation. The layout of a typical pit system is shown in Figure 1.

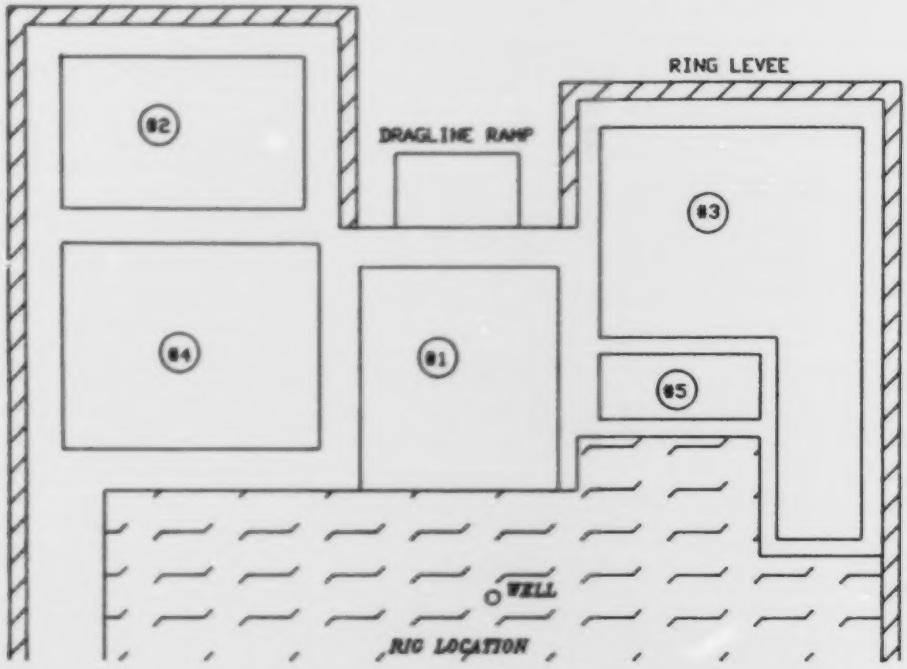

FIGURE 1. Typical Layout of a Managed Pit System

Pit # 1, the Shaker Pit receives drill cuttings from the shale shakers. The solids in this pit are moved, as needed, into Pit # 2, the Storage Pit. Liquids from the Shaker Pit are transferred into Pit # 3, the Settling Pit. If necessary, either rain water or water from Pit # 3 can be pumped into Pit # 4, the Treating Pit. Pit # 5 is an Emergency Pit. The number, size, and arrangement of the pits can be modified as needed.

The ability to move solids from Pit # 1 to Pit # 2 allows the operator to segregate uncontaminated solids from contaminated solids. Even solids that are suspected to be contaminated can be segregated while awaiting the results of laboratory analyses. Solids from Pit # 2 can be removed from the pit during the drilling operation and managed appropriately. This management option is not available using a conventional reserve pit.

Liquids may be managed similarly. Liquids are moved from Pit # 1 into Pit # 2 for the purpose of gravity settling and, if necessary, into Pit # 3 for chemical treating prior to discharge. Pits # 2 and 3 provide a reservoir for rain water that will keep the relatively clean rain water from contacting the solids which frequently contaminate the rain water. By careful management, rain water can be segregated from contaminants and discharged without any treatment. This greatly reduces the volume of liquids that have to be treated since rain water can account for up to 50% of the liquid in a conventional reserve pit. The rain water, water from the settling pit, or treated water is available for use as make-up water in the mud system, resulting in further savings.

Case Studies

Twelve case studies will be presented which support the use of the managed pit system. Two studies are wells which used the Managed Pit System. Three wells used a conventional pit and onsite treatment/disposal. Three wells used a conventional pit and offsite commercial treatment/disposal, one well used a closed system with onsite treatment/disposal, and three wells used a closed system with offsite commercial treatment/disposal.

The data and information detailed below is summarized in Table 1.

Case # 1

Case # 1 well was a 17,800 foot well drilled in Acadia Parish, Louisiana, using a Managed Pit System. The drilling of the well generated 59,236 barrels of drilling waste. By utilizing the sectioned reserve pit and managing the waste as it was generated, 43,200 barrels of waste were handled onsite by treating and discharging the liquids and landfarming and injecting the solids. Due to difficulties during annular injection, 16,036 barrels of waste had to be hauled to an offsite commercial facility for treatment and/or disposal at a cost of $3.66 per barrel. The cost of onsite treatment/disposal was $1.16 per barrel. The total cost of waste management was $1.84 per barrel. If the majority of the waste had not been treated and disposed of onsite, it is projected that the entire pit contents would have had to be taken to commercial facilities at an additional cost of $64,709, for a total cost of $173,670, This would increase the disposal costs to $2.93 per barrel, an increase of $1.09 per barrel.

Case # 2

Case # 2 is a well that is nearing completion in Cameron Parish, Louisiana, at a proposed depth of 19,000 feet. Though not complete, it is felt that enough data has been generated using the Managed Pit System for this well to provide significant information. Currently the well is at a depth of 16,356 feet and has generated 129,000 barrels of waste. Much of this volume is rain water which has been collected in the pits and on the location. The liquid has been treated and discharged. The waste solids have been landfarmed adjacent to the site. Current waste treatment/disposal costs are $0.40 per barrel. It is anticipated that all wastes will be treated and disposed of onsite and the final costs are projected to be about $0.50 per barrel.

Case # 3

Case # 3 is a well drilled in East Feleciana Parish, Louisiana to a depth of 16,100 feet using a conventional reserve pit. All wastes were either injected via annular injection or buried on site. A total of 31,935 barrels of drilling waste was disposed of at a cost of $35,428 or $1.11/barrel.

Case # 4

Case # 4 is essentially a twin of Case # 3. This well was also drilled in East Feleciana Parish, Louisiana to a depth of 16,170 feet using a conventional reserve pit. 26,451 barrels of waste were disposed of by injection and burial. The disposal cost was $33,182 or $1.25/barrel.

Case # 5

Case # 5 is a well drilled in Acadia Parish, Louisiana to a depth of 15,000 feet using a closed system. The use of the closed system was required because of the limited area available for the drill site. The cuttings were stacked on location and dried. Fly ash was added to stabilize and dry the waste prior to landfarming. At approximately 10,500 feet, it was calculated that the contaminate concentration in the mud and cuttings had increased to a level that onsite landfarming was no longer feasible and the waste was hauled to a commercial facility. The total cost for waste handling, both onsite landfarming and commercial disposal was $85,571. The additional cost for the

closed system was $36,000. The total volume of waste generated was 32,000 barrels. The cost for disposal was $3.81/barrel.

Case # 6

Case # 6 is a well drilled in Allen Parish, Louisiana to a depth of 10,500 feet using a conventional reserve pit. Approximately 14,650 barrels of drilling waste was generated. Approximately 12,150 barrels of pumpable waste were disposed by annular injection at a cost of $1.07/barrel. The remaining waste was landfarmed on site.

A post-closure sample of the landfarming area was taken and the results of the analyses showed that the area did not meet the requirements of Louisiana Office of Conservation's Statewide Order 29-B. Further studies determined that the area could be brought into compliance with the addition of gypsum and further landfarming. The two landfarming operations cost $8,000. The total cost of waste disposal was $20,950 or $1.43/barrel.

Case # 7

Case # 7 is a well drilled in Covington County, Mississippi to a depth of 14,400 feet using a conventional reserve pit. The wastes generated by drilling this well were to be disposed of by annular injection. The design of the location allowed rain water and other waste water run-off from the drill site to enter the reserve pit. Near completion of drilling, the reserve pit reached capacity and it was necessary to haul pit fluids to offsite disposal. Upon completion of the drilling, the annular injection was begun, but almost immediately, problems forced cessation of injection . There was inadequate area for landfarming so remaining liquids were treated and discharged. All residual liquids and solids had to be taken to offsite facilities. The total cost for the waste management was $102,583 or $2.28 per barrel.

Case # 8

Case # 8 was to Case # 7, a 14,400 foot well was drilled in Covington County, Mississippi using a conventional reserve pit. Again annular injection was planned as the disposal method, and again injection problems prevented the injection of the pit contents. This well encountered salt and the entire pit contents were contaminated to a point that treatment and discharge of the pit liquids was not allowed, and landfarming was not possible.

All waste had to be taken to offsite facilities. The cost for disposing of 54,900 barrels of waste was $200,262 or $3.65 per barrel.

Case # 9

Case # 9 was a 17,300 foot well drilled in Cameron Parish, Louisiana, in the same field as Case # 2. A concept similar to the Managed Pit System was designed and utilized at this site. An existing pit was used as one of the four pits in the system. Though it was anticipated that the pit contained contaminants, it was thought that those contaminants could be managed along with the drilling wastes generated during the drilling of the well.

Due to construction problems, pit walls separating the various pits were breached allowing the uncontaminated pit contents to be contaminated with barium from contaminated pit contents. The result was that no solids could be treated and disposed of on site and all solid wastes had to be hauled to a commercial facility. It was possible to treat and discharge most of the liquid wastes. The cost of disposal of the 100,000 barrels of waste from this well was $400,000 or $4.00 per barrel.

Case # 10

Case # 10 was drilled in Newton County, Texas, to a depth of 11,800 feet. Due to space limitations, a closed loop system with an integrated solids control system was used. 10,447 barrels of drilling waste were generated. To offset the high cost of offsite disposal, the same waste management practices characteristic of the Pit Management System were applied to the waste generated from this well. Wastes were segregated into three general categories; injectable fluids, uncontaminated solids, and contaminated solids. Wastes were handled by the appropriate disposal method, annular injection, onsite landfarming, and commercial disposal. Though the disposal costs were high, it was felt that this management practice reduced the disposal cost. The disposal cost was $34,826 or $3.33 per barrel. When the incremental cost of $39,000 for the closed loop system was added to this cost, the disposal costs per barrel increased to $6.61.

Case # 11

Case # 11 was a well drilled in Acadia Parish, Louisiana to a depth of 15,350 feet. The land owner would not allow the

application of any drilling waste to his land so the use of a reserve pit and burial and/or landfarming was not possible. A closed loop system was used and all waste was hauled to a commercial disposal facility.

23,930 barrels of drilling waste was disposed of at a cost of $105,180 or $4.40 per barrel. The incremental cost of the closed system must be added to this bringing the total cost to $168,180 or $7.03 per barrel.

Case # 12

Case # 12 was drilled in Lafourche Parish, Louisiana to a depth of 12,400 feet using a closed system. Because this well was located in a swamp with limited land area, landfarming was not possible and hauling to a commercial facility was planned. 14,000 barrels of waste was hauled at a cost of $98,000 or $7.00 per barrel. Adding the incremental cost of the closed system, the costs increase by $91,800 to $189,000 for a cost per barrel of $13.50.

Discussion of Case Studies

One of the advantages of the of the Pit Management System is the ability to handle most of the waste during the drilling operation rather than at the completion of drilling. Our experience has shown that this option should be utilized for several reasons. First, and perhaps most importantly, it forces the rig personnel to become more involved with the management of the drilling wastes and to realize the effects that their actions and decisions have on the wastes and waste management options.

Secondly, it reduces or eliminates the possibility of contaminating the majority of waste with the more contaminated wastes typically generated near the end of drilling operations when heavier, more complicated muds are used and when contaminated formations are most commonly encountered. Cases # 8 and 9 support this. In Case # 8, the entire contents of the reserve pit was contaminated by salt cuttings and when the anticipated disposal practice, annular injection, failed the entire pit contents had to be hauled to offsite disposal. If a Managed Pit System had been employed, the majority of the wastes could have been handled on site by either burial or landfarming and it is estimated that the disposal costs could have been reduced by approximately 50 %.

TABLE 1

SUMMARY OF DATA

EXAMPLE NUMBER	LOCATION	DEPTH (FT)	WASTE HANDLING SYSTEM	INTENDED TREATMENT/DISPOSAL METHOD	VOLUME OF WASTE (BBL)	COST	COST/ BARREL
1	ACADIA PARISH, LA.	17,800	MANAGED PIT	ANNULAR INJECTION/LANDFARM	59,236	$108,961	$1.84
2	CAMERON PARISH, LA.	16,350	MANAGED PIT	ANNULAR INJECTION/LANDFARM	129,000	$ 51,080	$0.40
3	E. FELECIANA PARISH, LA.	16,100	CONVENTIONAL PIT	ANNULAR INJECTION/BURIAL	31,935	$ 35,428	$1.11
4	E. FELECIANA PARISH, LA.	16,170	CONVENTIONAL PIT	ANNULAR INJECTION/LANDFARM	26,451	$ 33,182	$1.25
5	ACADIA PARISH, LA.	15,000	CLOSED SYSTEM	ANNULAR INJECTION/LANDFARM	32,000	$ 85,571	$2.67
6	ALLEN PARISH, LA	10,350	CONVENTIONAL PIT	ANNULAR INJECTION/LANDFARM	14,650	$ 20,950	$1.43
7	COVINGTON COUNTY, MS.	14,400	CONVENTIONAL PIT	COMMERCIAL FACILITY	45,000	$102,583	$2.28
8	COVINGTON COUNTY, MS.	14,400	CONVENTIONAL PIT	COMMERCIAL FACILITY	54,900	$200,262	$3.65
9	CAMERON PARISH, LA.	17,300	CONVENTIONAL PIT	COMMERCIAL FACILITY	100,000 EST	$400,000	$4.00
10	NEWTON COUNTY, TX.	11,800	CLOSED SYSTEM	COMMERCIAL FACILITY	10,447	$ 34,826	$3.33
11	ACADIA PARISH, LA.	15,350	CLOSED SYSTEM	COMMERCIAL FACILITY	23,930	$105,180	$4.40
12	LAFOURCHE PARISH, LA.	12,400	CLOSED SYSTEM	COMMERCIAL FACILITY	12,000	$ 84,000	$7.00

and it is estimated that the disposal costs could have been reduced by approximately 50 %.

In Case # 9, internal pit walls separating pit segments were breached allowing drilling wastes with high barium content from barite to contaminate the entire pit contents. Since no waste had been removed from the pit system and treated on site, the entire pit contents had to be hauled to a commercial facility. If the Managed Pit System had been constructed properly and if the waste would have been managed as it was generated, the waste disposal costs could have been reduced by an estimated 50 %, also.

Planning is one of the keys to the successful application of a Managed Pit System. Designing the drill site and pit system in a manner that prevents the majority of uncontaminated storm water from entering pits containing contaminants can greatly reduce the volume of liquid that has to be treated. This can result in significant savings. Case # 2 is an example where a large volume of liquid was effectively managed, contamination was minimized, and disposal costs were kept very low.

Closed mud systems (closed loop systems) have been used recently in situations where total haul-off of all of the drilling wastes is anticipated. The closed system is used to reduce the waste volumes, thus reducing disposal costs. Most commonly, the increased equipment costs required of the closed system more than off set the savings resulting from the reduction in waste generation. The Managed Pit System is an effective compromise. The segregation of the waste can result in saving in several ways. Relatively uncontaminated wastes are frequently disposed of at lower costs at many commercial facilities. Segregation of the liquid wastes results in more water that can be discharged at the drilling site resulting in less liquid being transported to disposal. Solids can be placed in one of the pits and allowed to dry further reducing the volume of waste to be transported and disposed. Comparing Cases # 1 and 2 to Cases # 5, 10, 11, and 12 shows that the use of the Managed Pit System can result in significant cost saving over the use of a closed system. Comparing Cases # 1 and 2 to Cases # 3 and 4, shows that the use of the Managed Pit System is very cost competitive with the use of a traditional reserve pit.

Other Considerations

Most operators are concerned about the continuing liability associated with the handling and disposal of their drilling wastes. Many feel that the liabilities are greatest at

reduce the volume of waste taken to commercial facilities. The Managed Pit System accomplishes this. An evaluation of the cases presented herein shows that over 70 % of drilling wastes can be handled on site. Most operators feel their liability is less with onsite disposal or treatment.

Conclusions

In reviewing the cases, it is apparent that the Pit Management System, when properly used, will reduce disposal costs. The case studies indicate that the isolation of wastes will prevent the contamination of the majority of the drilling wastes. This will maximize onsite treatment or disposal and greatly reduced costs. The planning, waste management practices, and monitoring of the waste will greatly reduce the possibility of contaminating significant volumes of waste because of "surprises". The case studies show that the Managed Pit System is cost competitive to all methods of drilling waste management.

FATE AND EFFECTS OF PRODUCED WATER DISCHARGES IN COASTAL ENVIRONMENTS

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Introduction

Produced waters, or oilfield brine, are generated during the production of oil or gas. Water that is trapped within the permeable sedimentary rock of the formation is brought to the surface with the product. This water, which is elevated in salinity and various organic and inorganic substances, may be reinjected or treated and discharged. The discharge of produced waters into brackish and marine waters is widespread in the northwestern Gulf of Mexico region and in coastal Alaska (1). In addition, discharges of produced waters into the Mississippi and Atchafalaya Rivers and their freshwater distributaries and into some intermittent streams leading to Texas estuaries are currently allowed (2).

The total emissions of produced waters into coastal and offshore environments in the Gulf of Mexico is estimated at 3.4 million barrels per day (2). Approximately 70% of these discharges enters the estuarine systems of Louisiana and Texas (Fig. 1). The distribution of these discharges is widespread throughout the coastal zones of both states, but discharges are more numerous and voluminous in southeastern Louisiana and on the upper Texas coast.

Discharge of oilfield brine, or produced waters, into the State waters of Louisiana is approximately 2 million barrels per day from nearly 700 sites (2). Most discharges average less than 1,000 bbl/d but a few exceed 50,000 to 100,000 bbl/d. In response to concerns about the fate and effects of produced waters in coastal environments, several studies have been conducted by state and federal agencies, university research groups, and private industry; other studies are nearing completion. Several sites representing different volumes of produced water discharges and different receiving environments have been examined for the delimitation of the scope and nature

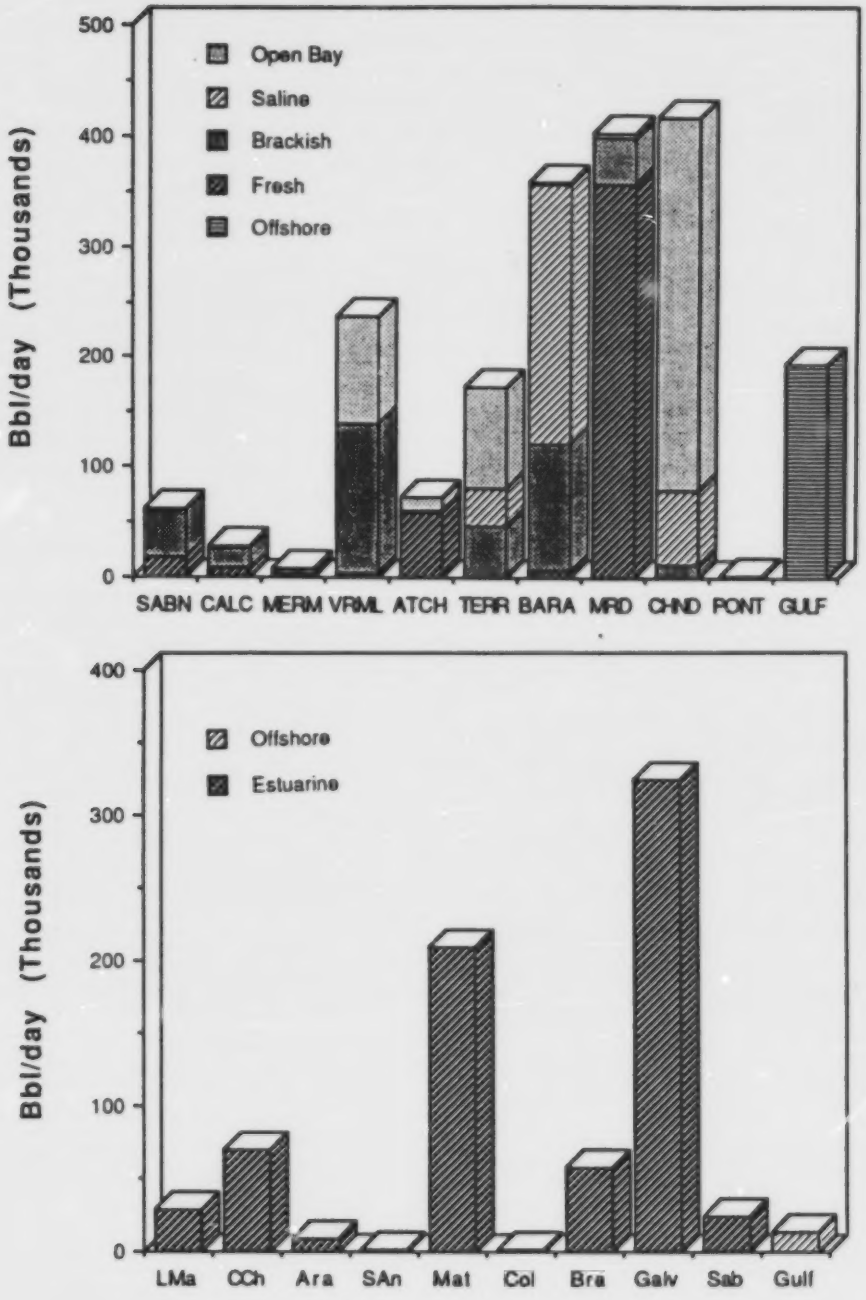

Fig. 1. Distribution of produced water discharges in Louisiana's estuarine basins or areas by habitat type, top, and in Texas coastal waters, bottom. [Modified from Boesch and Rabalais (2)]

of the impacts from these effluents. Selected results from case studies in fresh, brackish, and saline marsh environments (2, 3) are presented; additional details are available in the complete reports.

Description of study areas

Of the 2 million barrels of produced waters discharged into the State waters of Louisiana daily, 23, 22, and 17 percent are discharged into fresh, brackish and saline wetland environments, respectively, with the remainder discharged into open embayments or nearshore Gulf of Mexico waters (2). Coastal facilities which separate produced water from product streams originating in the Federally-controlled outer continental shelf (OCS) are few in number but account for large volumes, individually and collectively. Three areas were the focus of a recently completed study funded by the Minerals Management Study (2) and are included in an expanded and ongoing study funded by MMS. These sites represent large volumes of OCS-generated produced water discharges: Bayou Rigaud, behind Grand Isle; Pass Fourchon; and the bay side of East Timbalier Island. Two facilities discharge large quantities of OCS-generated produced waters into Bayou Rigaud. Volumes of 105,000 bbd/d and 45,000 bbl/d enter the dredged channel within 1 km of each other. Tidal currents through the northeastern end of Bayou Rigaud are swift, being influenced by tidal exchange through the nearby Barataria Pass. Two facilities discharge a total of 45,000 bbl/d at the Pass Fourchon study site; 26,000 bbl/d of this volume are generated on the Federal OCS. The effluents enter a dead-end canal which leads into Pass Fourchon, which itself is occluded by a beach with shoreline stabilization structures. The receiving canal and dead-end arm of Pass Fourchon are poorly flushed by tidal currents which are otherwise quite strong through Belle Pass and Pass Fourchon into Bayou Lafourche and the network of canals to the east of Pass Fourchon. A total of 24,000 bbl/d of OCS produced waters are discharged from three facilities at the East Timbalier Island study site. The three effluents are located in dredged access channels leading from the otherwise shallow Timbalier Bay into East Timbalier Island. Tidal currents flow sluggishly through the canal network. Details of the large-volume discharge study areas are given in Boesch and Rabalais (2).

The focus of the study funded by the Louisiana Division of the Mid-Continent Oil and Gas Association was on discharges into fresh and brackish environments. One site was located in a tidally influenced, fresh marsh environment within the Bayou Sale oil field. The discharge volume averaged 2,700 bbl/d and terminated in a dredged access canal. Two sites were selected in brackish marsh environments, one within the Lafitte oil field in the Barataria estuarine basin (ambient salinity at time of sampling 6 to 7 ppt) and the other in the Golden Meadow oil field in the Terrebonne estuarine basin (ambient salinity 9 to 10 ppt). The discharge rate for the Lafitte facility was 3,7000 bbl/d and the effluent entered a dredged north-south bayou intersecting some natural open water areas which have been extensively channelized. Two discharge points were examined in the Golden Meadow field: 1) 1,400 bbl/d in a dredged bayou and 2) 2,800 bbl/d in a dredged canal. In each of the above three study areas, station grids were located on combinations of dredged canals, canals which intersected some natural water

areas, or natural bayous. Details of the study areas are given in Boesch and Rabalais (3).

Characteristics of the discharge plume

Based on measurements of salinity in the vicinity of the discharges at the time of field sampling, it is possible to develop a crude picture of the fate and dilution of the effluent, using salt as a conservative tracer. At all sites investigated, there was an increase in salinity in bottom waters near the point of discharge, but surface salinities showed little or no increase over ambient conditions (2, 3). Produced water effluents act as a dense plume upon discharge into estuarine waters because of the high concentration of dissolved solids. Elevated levels of salinity, and sometimes volatile organics, were found just above the bottom near discharges (2, 3). The probable source of the volatile organics was the effluent plume rather than the sediments because these more soluble compounds are not particularly concentrated in the sediments (2, 3).

Dilution of the produced water upon its discharge into the receiving bayou or canal appeared to be rapid, with an approximately 20-fold dilution within the immediate mixing zone of the bottom-hugging dispersion plume. Salinity levels at the bottom were indistinguishable from background levels (necessitating at least a 100-fold dilution) within a maximum of 1000 meters of the discharge points. Where bottom currents are swift, sufficient turbulence is generated to mix the bottom-hugging plume. Consequently elevated bottom salinities, and sometimes volatile organics in overlying waters, were not observed beyond the immediate vicinity of the discharge at Bayou Rigaud and Golden Meadow. On the other hand, where tidal flows are much less energetic because of the dead-end nature of a receiving environment or restricted water movement because of altered hydrography, the density plume retained its identity for greater distances (e.g., Bayou Sale, Lafitte, Pass Fourchon) (Fig. 2).

Contamination of sediments

Sediments up to one kilometer from the produced water discharges exhibited evidence of petroleum contamination (2, 3). Contaminated sediments were typified by 1) elevated concentrations of polynuclear aromatic (PAH) and saturated hydrocarbons, 2) the presence of petroleum-derived PAHs, 3) alkyl-substituted homologs at higher concentrations than unalkylated parents, and 3) a fossil fuel pollution index which indicated that more than one-half of the PAHs were of petroleum origin (FFPI > 0.5) (2, 3). Sediments well removed from the discharges contained trace or non-detectable levels of petroleum-derived hydrocarbons and a FFPI < 0.3. PAH in these sediments, if detected, were usually pyrogenic in origin. PAH concentrations and characteristics were more useful than saturated hydrocarbons in determining the likelihood of contamination by produced water discharges (2). The resolved saturated hydrocarbons were usually very weathered with no homologous series of alkanes present, even in contaminated sediments. This lack of alkanes made the use of indices such as odd-even preferences, pristane/nC-17, and phytane/nC-18 of little use in quantifying petroleum hydrocarbon concentration.

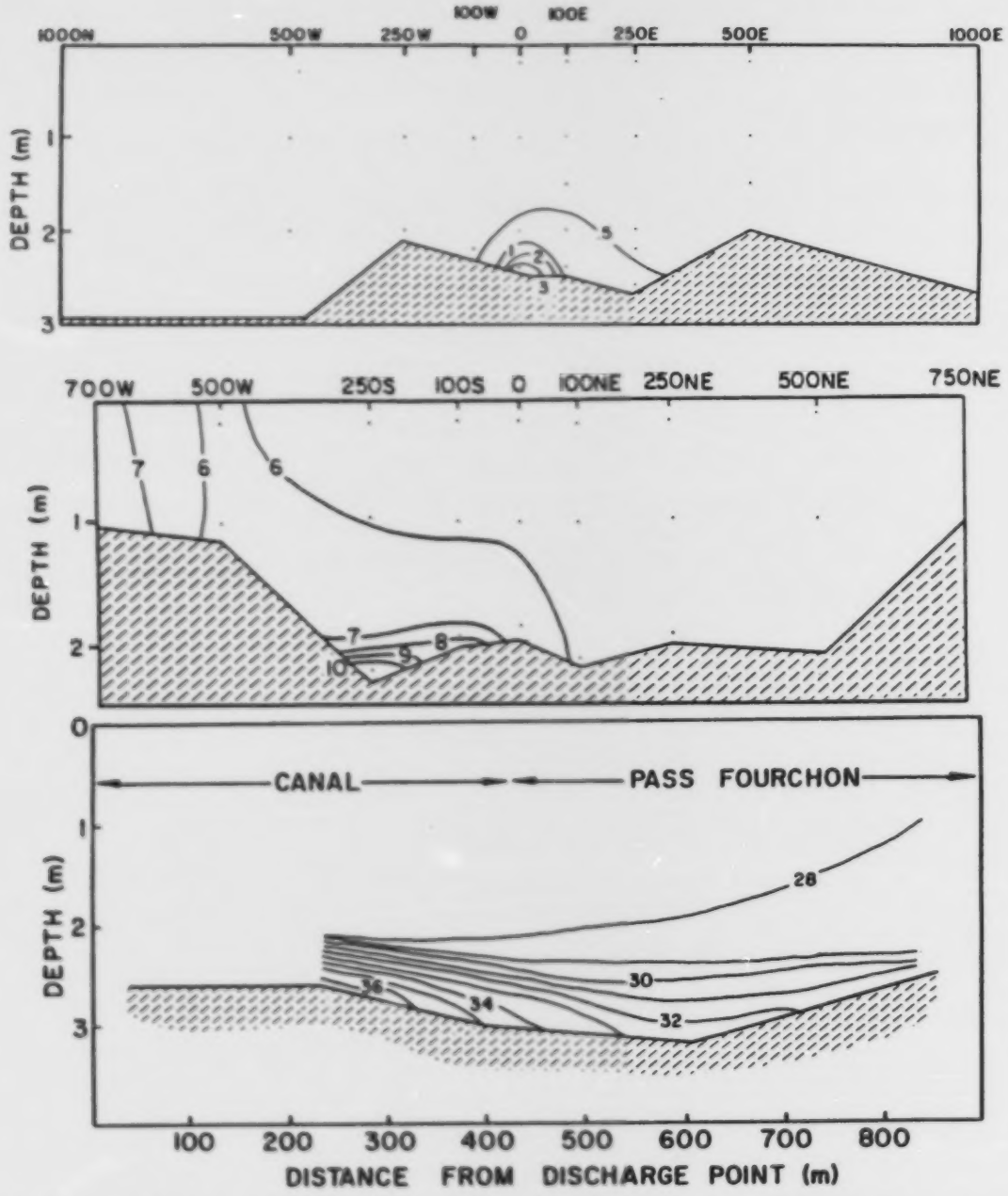

Fig. 2. Water column salinity (ppt) profiles at mid-channel in the discharge area at the Bayou Sale site in August 1988, top; in the discharge area along the NE-W transect at the Lafitte site in August 1988, middle; and along the access canal and adjacent Pass Fourchon in January 1988, bottom. [Modified from Boesch and Rabalais (2,3)]

Hydrocarbon contamination of bottom sediments was more extensive where discharge volumes were large and/or where tidal current velocities were reduced and where fine sediments accumulated. In Bayou Rigaud, where 150,000 bbl/d of two combined effluents are discharged, elevated levels of PAHs and saturated hydrocarbons were evident at station BR-1, proximate to the largest discharge (Fig. 3), and the FFPI indicated petroleum hydrocarbon contamination to a distance of 500 m from the discharge. Where smaller volumes (2,700 to 3,800 bbl/d) are discharged into dredged canals or bayous, PAHs are elevated near the discharge and up to 500 m from the discharge (Fig. 4, Bayou Sale and Lafitte). In other instances, however, elevated PAHs are evident within only 100 to 250 m of the discharge (Fig. 4, Golden Meadow).

The degree of contamination of bottom sediments by trace metals contained in the produced waters is far less than that for petroleum hydrocarbons (2). Strong outliers from the aluminum concentration in surficial sediments are generally an indication of sites of probable contamination. Sediments showing probable zinc contamination were found at stations near the large-volume produced water discharges in Bayou Rigaud and Pass Fourchon (Fig. 5). Fewer sediment samples showed variation from the linear relationship between aluminum and lead (Fig. 5); elevated levels of barium in surficial sediments were not consistent with discharge locations. For the smaller-volume discharges (Bayou Sale, Lafitte, Golden Meadow), trace metals, except for barium, did not show a consistent pattern of enrichment in sediments near produced water discharges (3).

Effects on benthic communities

The benthic environments adjacent to produced water discharges that were examined ranged from freshwater to saline (2, 3). In most cases, the environments were disturbed benthic habitats even without the effects of produced water contaminants. These environments were channels in which fine sediments accumulate, which are periodically dredged, and in which vessel traffic disturbs the bottom. In each site investigated, differences in benthic fauna were examined with consideration of the fauna in as similar a physiographic and hydrographic regime as possible.

In the study of large-volume discharges (2), the macrobenthic fauna was essentially eliminated at locations closest to the discharge where bottom sediments were heavily contaminated (PAH > 2,300 ppb). Low densities of organisms and few species were found under conditions of moderate hydrocarbon contamination of sediments (PAH > 200 ppb).

In the second study cited above (3) where the volume of discharges were one to two orders of magnitude smaller, the levels of contamination were consistent with the same differences in benthic macroinfauna. Benthic organisms were present in reduced densities and reduced diversity of species where there was high to moderate contamination of sediments by petroleum hydrocarbons (PAH > 1,000 ppb) (Fig. 6). There were changes in species composition and population size structure in areas of moderate contamination (> 300 ppb PAH) when compared to uncontaminated sediments (Fig. 6). The effects on benthos were

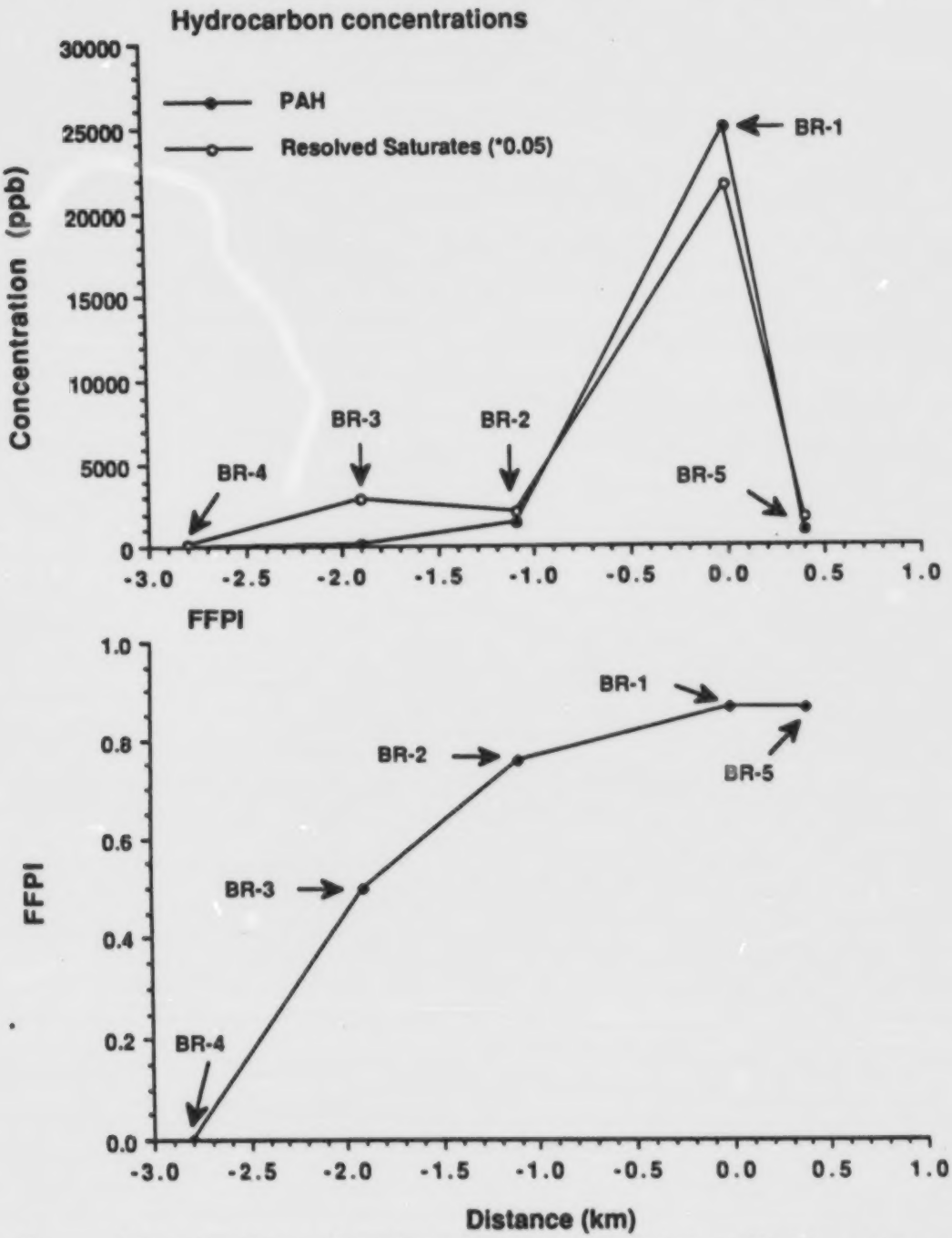

Fig. 3. Concentrations of hydrocarbons in surficial sediments, top, and FFPI, bottom, with distance from station BR-1 in Bayou Rigaud in October 1987. [From Boesch and Rabalais (2)]

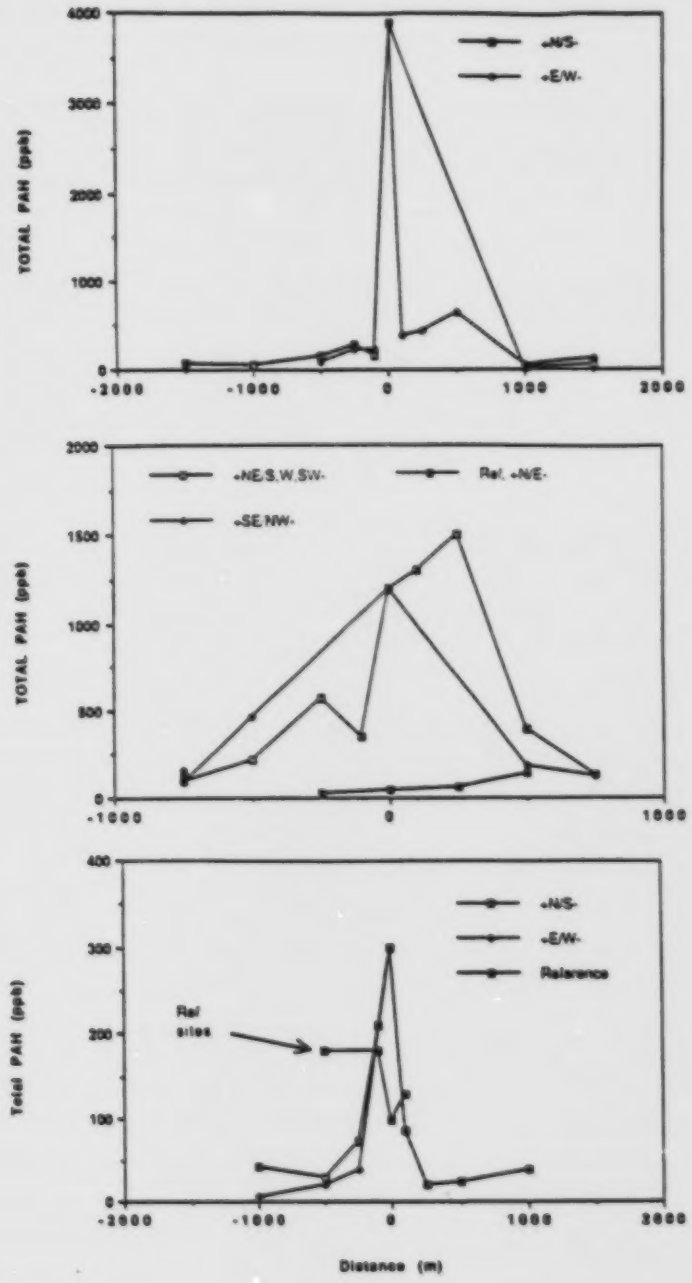

Fig. 4. Spatial distribution of normal PAH in discharge and reference site surficial sediments for study areas at Bayou Sale, top; Lafitte, middle; and Golden Meadow primary site, bottom. Note differences in scale. [From Boesch and Rabalais (3)]

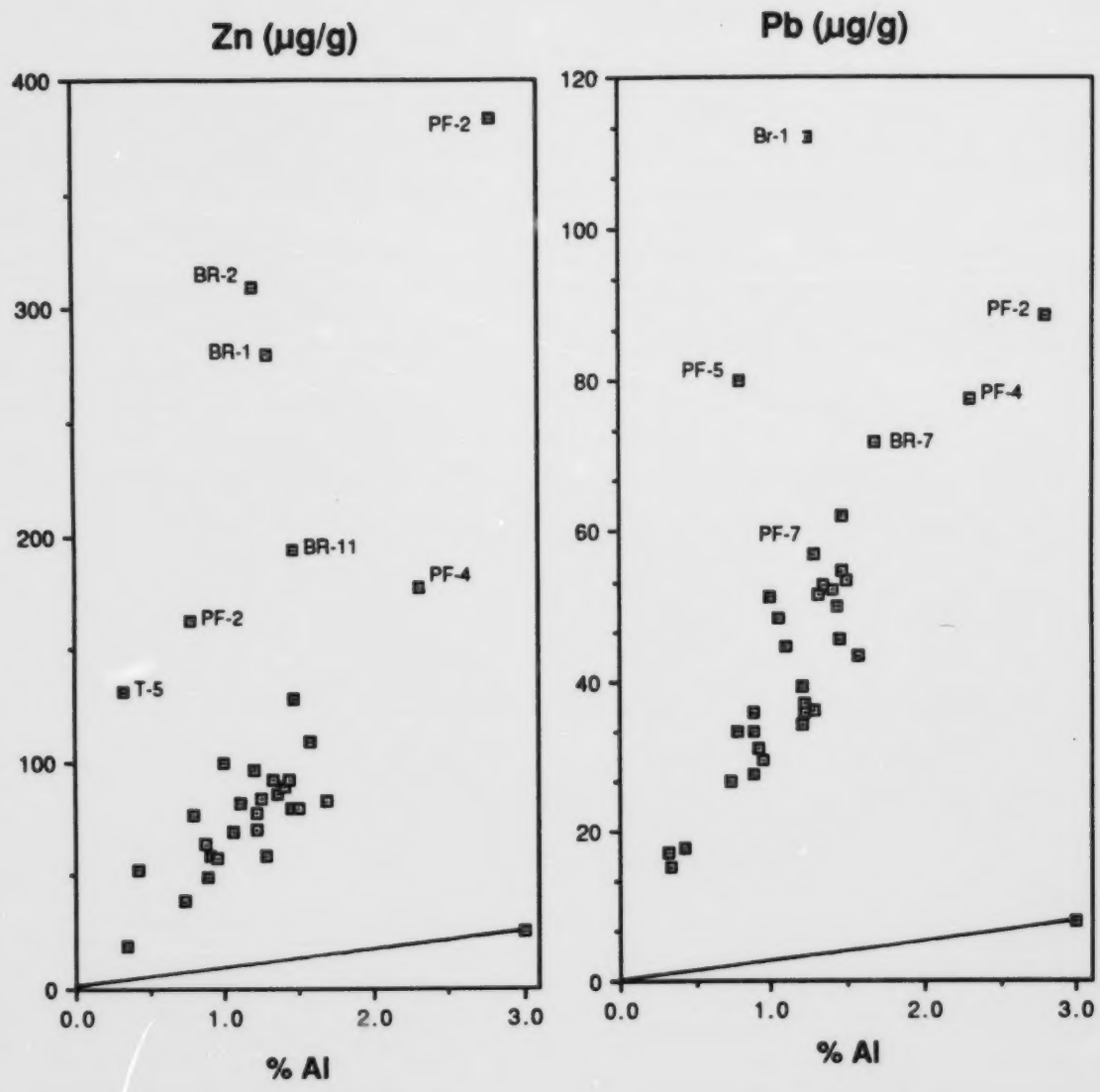

Fig. 5. Relationship of Zn and Pb to Al in surficial sediments at all produced water sites in the study by Boesch and Rabalais (2). Some station numbers given next to data. Lines represent the expected concentrations of a metal in the sediments based on the aluminum concentration. [Modified from Boesch and Rabalais (2)]

greatest at the Lafitte site, where only very depauperate populations of brackish water polychaete worms were found within 250 to 300 m of the discharge (Fig. 6). Effects on benthos in the freshwater habitat at Bayou Sale were less severe (3). Near the produced water discharge there, the diversity of the fauna was reduced but oligochaete worms were present in higher densities than were found in uncontaminated sediments. Increases in oligochaete population size have been characterized in the literature (4) as benthic community changes in tidal freshwater and estuarine areas in response to physical disturbance and organic pollution. Because ambient salinity conditions at the Golden Meadow site were higher, more species of benthos occurred there than at the other two sites. Even under conditions of moderate sediment contamination near the discharges, no depressions in total faunal abundance or diversity were found (Fig. 6).

Comparison of fate and effects

The principal impacts uncovered in the two studies (2, 3) are related to the contamination of the estuarine environment with organic compounds and metals contained in the produced waters and the effects on the benthic communities. There is considerable variation in the level and extent of bottom sediment contamination at the sites which is a function of the volumes discharged and the hydrodynamic and sedimentologic features of the sites. The heaviest contamination and the most extensive impacts were seen where the discharge volumes are extremely large (Bayou Rigaud) and/or where the tidal flushing rates are low (the dead-end canal system at Pass Fourchon). The levels of contamination reported for the three sites with smaller discharges (3) were generally an order or two of magnitude less than those reported for more saline environments with larger volumes of produced water discharges (2). Given comparable discharges, less contamination is witnessed in regions with vigorous tidal flushing, such as Golden Meadow, compared to less flushed sites, such as Lafitte. The range of effects on benthic communities seen within the study areas were 1) low densities of organisms and few species under conditions of high to moderate hydrocarbon contamination of sediments, 2) changes in the species composition and population structure in areas of moderate contamination, or 3) no obvious effects in areas of low hydrocarbon contamination.

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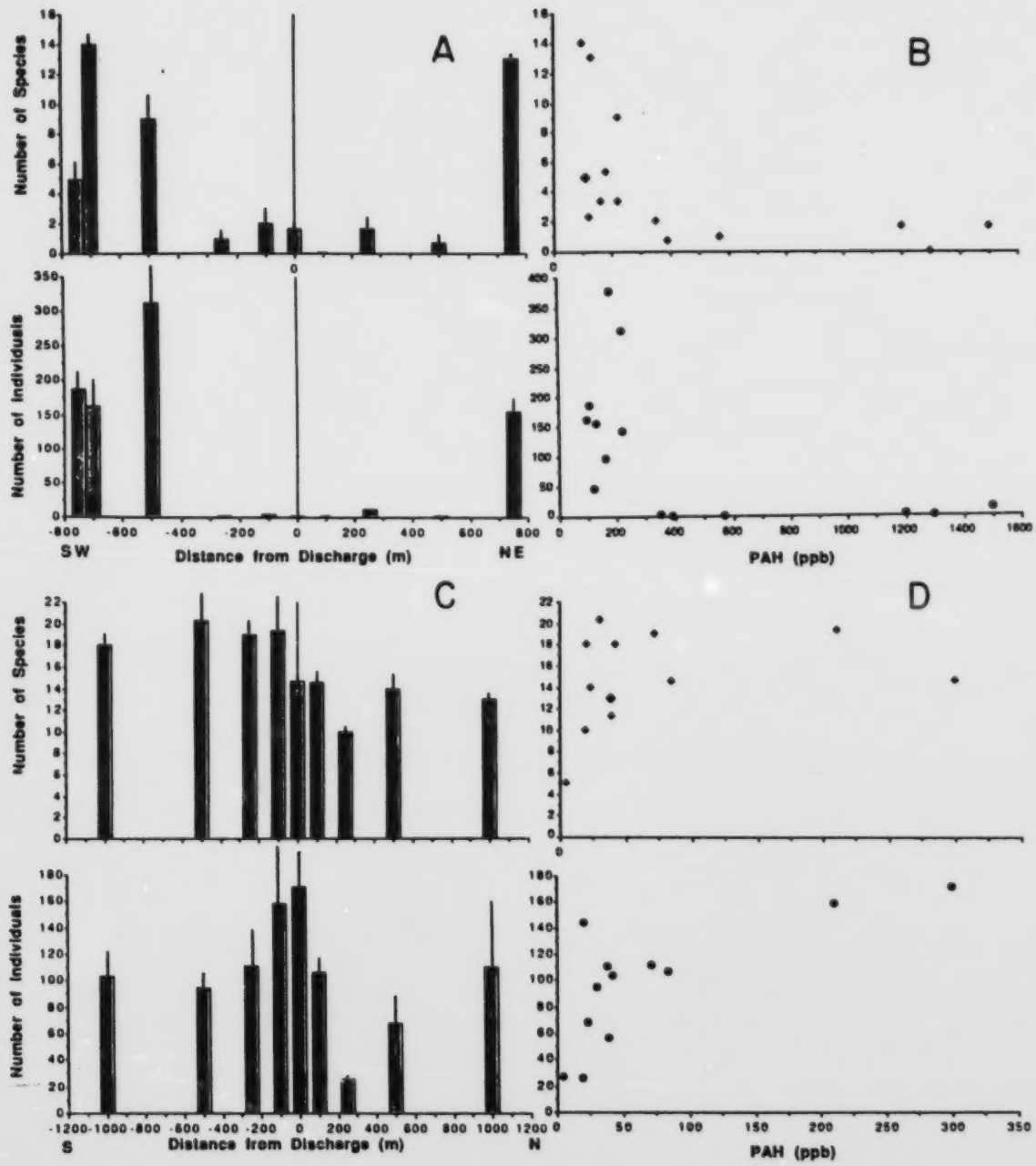

Fig. 6. Number of species per replicate and number of individuals per replicate (± S.E.) for benthic macroinfauna along a NE-SW transect through the Lafitte discharge site (A); comparison of number of species and number of individuals to polynuclear aromatic hydrocarbons (PAH) for the Lafitte discharge site (B); similar data for benthic macroinfauna along a N-S transect through the Golden Meadow primary discharge site (C) and (D). Note differences in scales. [Modified from Boesch and Rabalais (3)]

3. D.F. Boesch and N.N. Rabalais (eds.), Environmental Impact of Produced Water Discharges in Coastal Louisiana, Report to The Louisiana Division of the Mid-Continent Oil and Gas Association, Louisiana Universities Marine Consortium, Chauvin, Louisiana, 1989, 287 pp.

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A HARMONIZED PROCEDURE FOR APPROVAL, EVALUATION AND TESTING OF OFFSHORE CHEMICALS AND DRILLING MUDS WITHIN THE PARIS COMMISSION AREA.

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Introduction

- The North Sea and The Paris Commission

The North Sea is one of the most productive seas in the world and has been one of the main supplier of fish to the European Common market. Surrounded by heavily industrialized and cultivated countries the North Sea receives large amounts of waste from landbased industrial activities, farming, sewages in addition to discharges from shipping and oil and gas explotations in the North Sea itself.

Over the last decades the public's worries about the state of the North Sea due to dumping and discharges of wastes and chemicals from industrial activities have increased. For the health of the public it is important that fish brought to the marked is uncontaminated. The occurence of diseased and contaminated fish is a very sensitive topic and reports documenting increased frequencies and/or concentrations can lead to restrictions on sales and import and thereby negative consequences for the fishing industry. It is thereforee very pertinent to prevent pollution of the North Sea.

The Paris Convention was established in 1974 and entered into force in 1978. For the prevention of marine pollution from land based sources in the North East Atlantic (including the North Sea). Under this convention "land based sources" are defined as including "man-made structures placed under the jurisdiction of a Contracting Party" and this includes offshore exploration and exploitation of petroleum-hydrocarbons. Article 1 in the Paris Convention states that "the Contracting Parties pledge themselves to take all possible steps to prevent pollution of the sea, by which is meant the introduction by man, directly or indirectly, of substances or energy into the marine environment (including estuaries) resulting in such deleterious effects as hazards to human health, harm to living resources and to marine ecosystems, damage to amenities or interference with other legitimate uses of the sea."

The Contracting Parties shall, jointly or individually as appropriate,

implement programmes and measures adopted by the commission. There has been agreed upon specific standards for discharges and emissions, control mesurements and monitoring methods, with the aim to reduce the pollution of the sea and to get a better documentation of the pollution level (e.g. on discharge of oil contaminated cuttings). Over the last years the increasing use of offshore chemicals has been looked upon as a problem area without satisfactory regulation.

- The use of chemicals in the offshore oil and gas activity

In connection to offshore activities fairly large amounts of drilling and production products/chemicals are used and discharged to the sea, either adhered to drill cuttings, or with produced water (table 1). These figures are from Norway, but similar discharges takes place in UK, the Netherlands and Denmark. Due to higher drilling activity and number of production platforms the total discharges will be higher in UK, and lower in the Netherlands and Denmark were the activity and number of platforms are lower.

TABLE 1

The use and discharges of some selected types of chemicals from Norwegian offshore installation in 1988 (tons), based on figures reported from the operators.

	DRILLING		PRODUCTION	
	used	disch.	used	disch.
Weight agents	146.000	86.000	-	-
Inorganic chem.	3.700	2.700	-	-
Polym.viscosif.	1.800	1.200	-	-
Biocids	30	25	1.400	35
Oxygen scaven.	2	1	1.000	12
Corrosion inhib.	90	40	1.100	15
Scale inhib.	60	60	1.100	750
Shale inhib.	2.500	2.500	-	-
Gas treatment	-	-	8.000	140
Others	3.875	1.544	1.051	400
Total	158.057	94.060	13.651	1.352

The effects on the marine environment due to discharges of oil contaminated drill cuttings have been documented several times (1, 2, 3)

As production persits and the fields gets "older", the fields normally produce more water (Fig.1) and an acidification may takes place. In an attempt to prevent corrosion of the platforms and the pipelines the operators have normally solved their problem by an increased use of

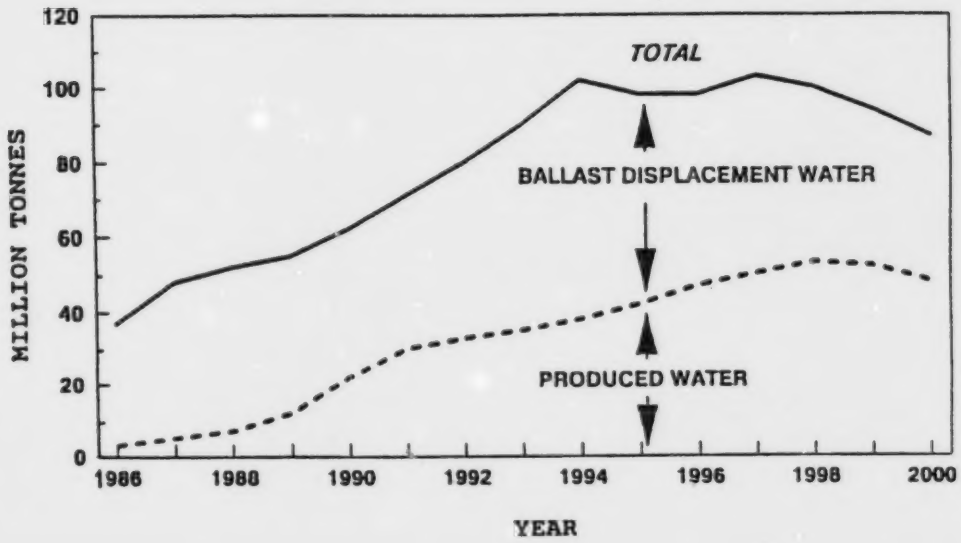

Fig. 1.: Projected increase in dicharge of water, based on figures presented by the operators.

chemicals. The most common "production" chemicals used are biocides, anti corrosion products, oxygen scavengers, anti scaling products (table 1). Chemicals are also used increasingly in an attempt to stimulate wells and fields in an attemt to produce more oil. In addition chemicals are used for maintainance of pipelines and large amounts of chemically treated water can be discharged over a short period into a limited sea area.

During the offshore process some of the chemicals will follow the oil or gas phase while others follow the water phase and thereby discharged to the sea as a part of the produced water. Some of these products may degrade very fast, while others are more stable and may be detected for a long period. Bioaccumulation of products is dependent on the lipophilic character of the product, some products may thereforee accumulates very fast (lipid soluble e.g. oil products) while others e.g. those with a high molecular weight may not accumulate. The toxicological effects are dependent both on the fate and concentration of the products, but also on the organisms exposed - e.g. the life stage, living and feeding behaviour etc. The fate and effects on the the marine environment of chemically treated water have been difficult to investigate due to methodological problems caused by the great dilution of the chemicals in the sea, continous exchange of water masses due to currents, etc. However, effects have been reported from laboratory tests on marine organisms (4, 5). For selection of the <u>right</u> chemical product, the operators have so far only focused on the technical problem and functional testdata have been the

only criteria. Only after special requests from the authorities potential environmental effects data have been searched for. Very often such data have either not been available because the products have not been tested for such information, or the data had low value since only tests on mammals (rats and rabbits) were those performed and none on marine organisms.

- Excisting practices for approval of offshore chemicals and muds

The North Sea states which have offshore activities are UK, Denmark, the Netherlands and Norway and they have previously introduced different systems for notification and approval of the use and discharge of offshore chemicals and drilling muds. For oil based drilling muds special requirements have been in force for toxicity testing during the 80-ties. However, the tests required have been different in the four countries, and thereby the same mud system had to be tested by four different test systems before approval in all four countries were achieved.

For all other offshore chemicals there have been no common mandatory requirements on testing. In UK there has been a voluntary notification system where the operator could report the amount discharged and document toxicity data if available. In Norway the discharge applications have been evaluated on a case by case basis, where the operator had to specify the amount to be used, the concentration used and discharged, and as exact information as possible on toxicity, biodegradation and bioaccumulation in the marine environment. Normally the data sheets received containes insufficient data on the product's fate and effects in the marine environment.

<u>The harmonized procedure</u>

In the mid 80-ties the Paris Commission commenced an attempt to harmonize the test requirements for oil based muds, so that repeated testing of the same product could be avoided. During this process the scope was extended to include all kind of muds and offshore chemicals, and the objectives were specified in such a way that the new system should increase the quality control for handling of all kinds of offshore chemicals and thereby reduce the pollution of the sea. The selection and approval of offshore chemicals should be more effective and thus reduce the cost and work involved.

Within the Paris Commission there has been a special working group of experts that has prepared the guidelines for the harmonization of procedures for approval, evaluation and testing of offshore chemicals and drilling muds. Norway has been lead country for this work, and scientists and authorities in UK, the Netherlands, Denmark, Sweden and Norway have participated in this work, Appendix 1. In addition representatives from the operators, the E&P Forum* and suppliers have been involved in parts of the work.

At the Paris Commission meeting in June 1990 the guidelines regarding harmonization of procedure for approval, evaluation and testing of offshore chemicals and drilling muds was adopted to be followed as close as possible on a trial basis. The guidelines will be reevaluated after a two years period.

- the decision tree
In Fig.2 a decision tree is presented. This tree is to be used by suppliers or producers in their search for products to be used offshore that are "acceptable" from an environmental point of view.

- the Paris Commissions black and grey lists
In box II (Fig.2) one has to check whether the actual product include substances which are listed in Annex A of the Paris Commission. Pollution of the maritime area from land-based sources by substances in Part I, Annex A (black list) are to be eliminated while substances in Part II, Annex A (grey list) are to be strictly limited, or as appropriate eliminated.

- the "green list"
In box III (Fig.2) there are listed products which are classified as "non hazardous" for the marine environment, e.g. composed by major constituents of the sea water or inert material. A list of products which do not need to be tested for toxicity, degradation or bioaccumulation before they are used offshore are under preparation within the Paris Commission, the "green list". Even "green list" substances or products might be subject to discharge restrictions in certain vulnerable area, and a discharge application has therefore to be sent to the authorities.

- the central data base
Box IV (Fig.2) is a very essential part of the system. That is the establishing of a central data base where all the product information specified in table 2 shall be stored and thereby be available for operators and authorities. By using this data base the operator should receive an overwiev of excisting products and their potensial environmental hazard, and thereby be able to avoid the most harmful products.

The data in table 2 is essential for the evaluation of potential environmental effects and is mainly based on the Minimum Data Set (MDS) and the SHOC report prepared by the E&P Forum. Some adjustments have been made by the Paris Commissions working group of experts. The list contains most of the information which also is required by the OECDs Minimum Premarketing Data set (the MPDs).

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*E&P Forum - The Oil Industries International Exploration & Production Forum.

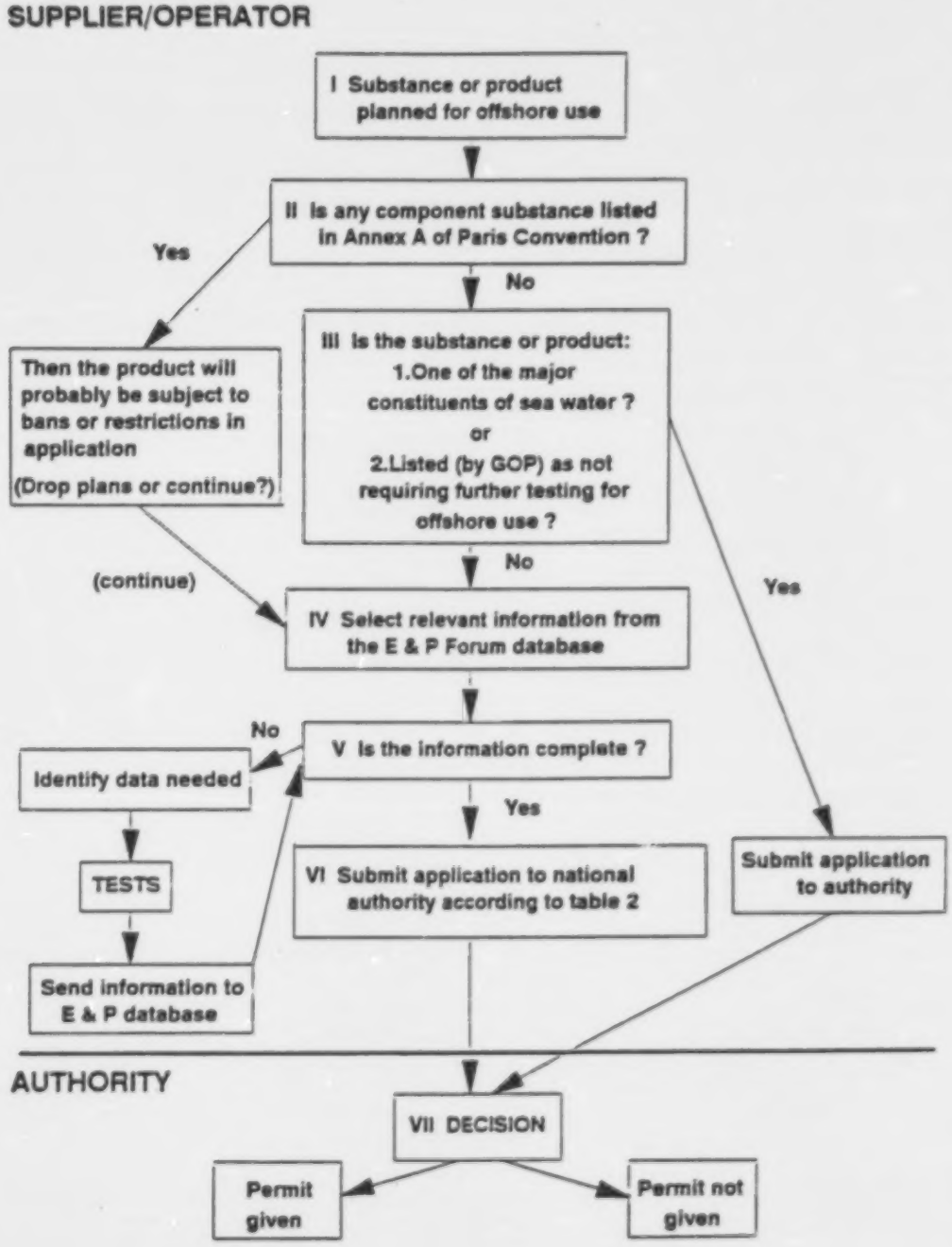
SUPPLIER/OPERATOR
I Substance or product planned for offshore use
II Is any component substance listed in Annex A of Paris Convention ?
Yes
No
Then the product will probably be subject to bans or restrictions in application
(Drop plans or continue?)
III Is the substance or product:
1.One of the major constituents of sea water ?
or
2.Listed (by GOP) as not requiring further testing for offshore use ?
(continue)
No
Yes
IV Select relevant information from the E & P Forum database
No
Identify data needed
V Is the information complete ?
Yes
TESTS
VI Submit application to national authority according to table 2
Submit application to authority
Send information to E & P database
AUTHORITY
VII DECISION
Permit given
Permit not given

Fig. 2.: Decision tree to be followed for selection of offshore chemicals and drilling muds.

TABLE 2

Product information regarding physical, chemical and biologial properties to be specified in an application for use and discharge of offshore chemicals and drilling muds.

PART I: SUPPLIER DATA

Trade names and synonyms of the product used in various countries:
Contact person in the company:
Position in the company:
Address:
Telephone no:
Emergency telephone no (24 hours):
Telefax no:
Country of manufacture/formulation:
Name and addres of supplier:

PART II: CHEMICAL COMPOSITION DATA

Application:
Composition: - single compound/mixture solution/suspension/emulsion
Chemical (or generic) composition *:
Active ingredients:
Solvents:

Analytical methods and procedures to detect and quantify the product in water, sediment and organisms.

Regulatory requirements:
Indicate if the product contains any compounds regulated under the Paris Convention Annex A.
- metals, organohalogens, organophosphorus compounds, organotin compounds, other listed.
- radioactive substances.

If yes, specify: item, concentration, trace **, intentional additive.

* In addition to these data stored in the central data base, the authorities will ask for Cas No. for all components in a mixture and the concentration of all components with % intervals: <1, 1-2, 2-5, 5-10, 10-20, 20-40, 40-60, 60-100. Where necessary the authorities may require 100% coposition.

** Trace is defined as less concentration than 0.01 % (100ppm).

PART III: PHYSICAL PROPERTIES

Physical form and appearance: solid/liquid/gas.
Odour and colour:

Density (kg/m), Boiling - and Melting points (C), Solubility in water and oil, pH (of saturated solution in water), Vapour pressure (mbar), Flash point (C) and OECDs requirements for special Fingerprints (e.g. spectra).

Bioaccumulation potential:
For mixtures this information should be available for all components (above trace content). The OECD test guidelines should be followed and n-octanol/water partition coefficient should be documented. For at least inorganic components the Biological Concentration Factor (BCF) should be documented.

PART IV: TOXICOLOGICAL DATA

Environmental data:
Results from acute toxicity tests on marine organisms has to be presented from at least one of the species listed in each of the three following groups:

ALGAE:

Phaeodactylum sp.
Skeletonema costatum

HERBIVOROUS:

Acartia tonsa
Chaetogammarus marinus
Mytilus edulis (adults)
Crassostera gigas

SEDIMENT REWORKING SPECIES:

Abra alba
Echinocardium cordatum
Polychaeta sp.

Biodegradation:
The OECD updated guidelines on marine tests for biodegradation (BOD-28) should be followed. For mixtures there should be available data on biodegradation (e.g. BOD) on all components in the mixture (above trace content), not for the total mixture. % degradation, time and method used have to be presented.

The E&P Forum in London has been asked to establish and administrate this data base and the plan is that a data base shall be operative during 1990. Ideally the North Sea states would have the Cas. No specified for all components in a mixture and the concentration of all components within % intervals (e.g. <1, 1-2, 2-5, 5-10, 10-20, 20-40, 40-60, 60-100%). This information was, however, considered to be confidential information by the industry and the E&P Forum would not store such information in a data base with an open access. Although such information will not be available from the central data base, it is expected that most countries will ask the operators to present these data in the application to the authorities. If the producers are not willing to submitt such data to the operators they can send these data directely to the authorities. In addition to the data specified in table 2, national authorities may require additional information to be submitted - on a confidential basis where necessary, e.g, 100% chemical composition. For this purpose trace contaminants are defined as less than 0.01% - ie lss than 100 ppm.

- the tests required

In table 2, part IV are listed the marine species which are included in the GOP* toxicity test system for offshore chemicals and drilling muds. At least results from one species in each of the three groups should be presented to the authorities.

This list is based on information available from tests that are operative in the North Sea states. The intention by this system is to minimize the chance for a toxic product to pass the test system without being classified as toxic. The following criteria have been used; a product should be tested for toxicity against marine species representing different feeding types, trophic levels and living biota, see table 3. Thereby the acute toxicity of products which are either water soluble, lipid soluble or "sedimentophilic" should be detected by the system.

Preferably long time (chronic) exposure tests under "realistic" conditions should be performed. Such tests would be rather costly and time consuming. As a compromice it was decided to base the approval system on acute tests and try to harmonize against existing international systems, e.g. the OECD's test Guidelines. A marine fish test is highly recommended to be included in the system, but it has not been possible for the group to specify such a test at present due to restricted availablitity of suitable tests and high cost. However, there is a recommendation that in special cases, e.g. planned discharges to sensitive areas the authorities should require toxicity testing on fish species relevant of the discharge area.

Until the toxicity test systems are operative, national authorities will accept test results from other tests covering similar group of test

*GOP - The Paris Commissions Working Group on Oil Pollution.

organisms, trophic levels and feeding type and living biota as those presented in table 2 part IV, see also Quality Assurance.

The authorities would preferably like to see the potential environmental hazard of the single products and mixtures discharged to the marine environment after being treated offshore (e.g. by high temperature and pressure in the well). Since this "treatment" is not easily obtained in a normal laboratory, the regulation is focused on the products as they are entering the offshore system. However, for planned discharges of large amounts of chemically treated water, e.g. emptying of pipelines, tests should be performed on the total mixture after a simulation.

In addition to the toxicity tests, data from test on biodegradation and bioaccumulation have to be presented. These tests should be based on the OECD guidelines for such tests, table 2 part III.

The toxicity should be tested on the "whole" product if it is a mixure of several chemicals due to possible synergistic effects. The documentation of accumulation and degradation should be for all single components in the mixture (above trace content).

Today most data on degradation is BOD data on a whole product. This information gives information on how much owygen is used, it does not give information on whether only some of the components in the mixture are degraded, or the change in toxicity is due to degradation. This is the reason why one ask for degradation information of all components.

TABLE 3
Some of the criteria used in the evaluation and selection of species to be incorporated in the test system:

FEEDING TYPE:	Filter- or deposite feeders, grazers or predators (hunters).
TROPHIC LEVEL:	Primary producers, herbivours etc.
BIOTOP:	Planktonic and benthic.
SENSITIVITY:	High, low or insensitiv.
REPRODUCIBILITY:	Important, but little info. avail.
BEHAVIOUR:	Avoidance, closing etc.
LETHAL/SUBLETHAL:	Subleathal are preferable.
TEST DOCUMENTATION:	Publication of the test method.
SIMPLICITY:	Which tests are comparatively simple?
AVAILABILITY OF TEST ORGANISM:	In laboratory culture or not?

- **check points**

Box V (Fig.2) is a check point to ensure that all necessary information

is available and documented by test protocols and results from the authoriced test-laboratories. The operator should at this point have available information on several products which could be used offshore to solve his problem. The selection of the "right" product should be based on a policy where the most "polluting products" are avoided.

Mutagenicity and carcinogenicity represent a significant problem and should also be part of the evaluation although there are some difficulties in testing and classification. In the decision tre these items should be evaluated after degradation and accumulation has been evaluated.

- application

If the operators have followed the decision tree, presented an application (box VI, Fig.2) with all requirements filled in (table 2) and documented test reports from test laboratories, it should be a relatively easy job for the Authorities to control the information given and make a decision regarding the specific application. By contacting the E&P Forum data base the Authorities can check that the "best environmental" products have been selected. If not the operator has to document why he has selected another product. If the authorities is not convinced by the operator another product has to be selected.

- decision

As a part of the scope, the group of experts should try to present specific criteria for decision (box VII in Fig.2) of "acceptable" discharges. However, at this stage it has not been possible to reach concensus. Several aspects are of importence for the evaluation of planned discharges. For instance the following: due to variation in areal sensitivity one product may have acute toxicity, biodegradation and bio-accumulation potentials that are acceptable for one area, but not for a more sensitive area. It may also occur that one product is acceptable during one season, but not during another e.g. due to migration of birds, fish etc. Further it is very difficult to introduce one specific concentration which is the limit for acceptable pass/not acceptable. This is due to several aspects, e.g. the test methods, toxic kinetic, species etc

One can not decide which products are acceptable for discharge into an area only by considering data regarding toxicity, biodegradation and bioaccumulation, but environmental data from the potential influence area hase to be taken into consideration. One ought to carry out an impact assessment of the planned discharges - alone and in relation to all other activities and discharges influencing the actual areas.

Within several international organizations there is work going on for identifying more and less "similar" selection/decision criteria, e.g. the Commission of the European Communities had a special meeting this summer regarding "The setting of a common selection scheme of dangerous

substances", the Scandinavian countries are preparing a system for classification and labeling of environmental hazard products, the MARPOL 73/78 Annex 2, and within the Oslo Commission there is ongoing work for evaluation of waste dumping to the marine environment (6). Hopefully within some years a group of experts will be able to present a list of criteria that can be used as Guidelines both for the selection and the decision process.

Quality Assurance (QA)

This is an important part of this system. How can users and authorities be sure that the product actually contains what is declared, and what requirements need to be enforced to ensure reliability on product information and test results - e.g. can one rely on test results from the producers own test-laboratories, or are results from independent test-laboratories needed? According to the group of experts the data specification in table 2, the Cas. No. and concentration intervals are basic parts of the QA. Special fingerprints (spectra) may also be required.

The authorities can at any time due to these data ask for control analysis of a product sold on the market and check whether the information given by the producer/importer are in accordance whith the commercial product.

The harmonized system requires that test laboratories receiving a product for testing shall check that properties specified by the producer are in accordance with the actual sample received e.g. melting point and specific gravity. If discordance with the specifications are observed the product should be returned without any further testing.

It has been decided thet the test laboratories either have to present a GLP-documentation, or be approved by national authorities. Within each of the four North Sea states there are specific institutions which are authorized to give GLP-documentation. This means that results from a producers laboratory can be accepted provided the laboratory has GLP-documentation. However, normally the individual authorities can require retesting or additional testing from independent laboratories.

Introduction of this harmonized system and performing of a ring test

This system entered into force from June 1990. However, the first two years will be a test period which will include a ring test for the toxicity tests and laboratories involved. In addition to the tests presented in table 2 part IV, other tests can be included in the ring test if the appropriate laboratories pay the cost.

In 1992 the Paris Commission group of experts will meet again and perform an evaluation of the whole system - including the data base. Based on

this evaluation a more permanent system will be proposed.

Denmark has kindly taken the offer to act as lead country for the administration of the ring test. However, each country, laboratories and the industry are expected to share the cost. Four test-substances have been chosen for the ringtest and the idea is that all tests should test the effect of those four products; 3,5,dichlorophenol, Bioban P-1487 (EPA reg. no 48301-7), Vantocil 1B, and an oil based drilling mud Carbo Sea DMA. The first product is already a standard used by the ISO system in their ring test for algaae. Bioban P-1487 and Vantocil 1B are biocids, with a different fate in the environment. Vantocil 1B is a product that has a tendency to adsorb to particles and thereforee be sedimentated - a "particulophilic" product.

Further research

This harmonized system as it is proposed is not "perfect". It is the intention that it will not be a static system, but improved and updated as soon as possible when new sientific results makes room for improvements. The group of experts recommended that research on the following items should be carried out:

- a fish test on marine species that can be performed all through the year.

- a combined toxicity and biodegradation test indicating what is degraded and the corresponding change in toxicity.

- a test for biodegradation on sparingly soluble products, e.g. surfactants which are difficult to test at present because they adhere to glass surfaces.

In addition I will personally add the research for better tests on bioaccumulation and especially for mixtures.

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APPENDIX 1:

The following persons participated at the Paris Commission workshop in Oslo, November 1989, where the harmonized system was discussed before the final preparation was done by Norway.

United Kingdom:
R.A.A. Blackman, MAFF.
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P. Worthington, DoE.

The Netherlands:
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P. Meertens, NSD.
K. Meijer, MoE.

Sweden:
M. Tarkpea, SNV.

E&P Forum:
W.de Ligny, Shell.
A.D. Read, E&P Forum.
J.A. Hansen, Statoil.

Denmark:
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M. Robson, MoE.
P. Wrang, Miljøstyrelsen.

Norway:
G. Halmø, SINTEF.
T. Kællquist, NIVA.
G.M. Skeie, CMS.
T. Strømgren, BIOCOSULT.
T. Syversen, UoT.
F. Thingstad, UoB.
I.G. Engeland, SFT.
L.-O. Reiersen, SFT.

IMO:
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HAZARDOUS WASTE TREATMENT/RESOURCE RECOVERY VIA HIGH TEMPERATURE THERMAL DISTILLATION

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INTRODUCTION

TEST BURNS/AFTER BURNERS/SCRUBBERS/ASH/OXIDIZED METALS/PUBLIC HEARINGS/TREATMENT PART B PERMITS/CARCINOGENIC EMISSIONS/ACID RAIN/N.I.M.B.Y. (Not In My Back Yard)

The preceding subjects have traditionally been associated with the hazardous waste treatment alternative, high temperature incineration. Until recently, incineration has been the preferred method of treatment. The process, however, by which a waste generator must go through in order to implement incineration is extremely tedious, time consuming, and, in many geographic areas, is simply an impossible task. The U.S. E.P.A.'s ban on the disposal of organics in land fills has put additional pressure on industry to remove the organics from waste prior to it's ultimate disposal and to perform the task in a fashion which is acceptable to the general public. As a result, increasing emphasis is being put on the use of recycling processes which both meet the E.P.A.'S disposal restrictions and can be readily implemented. The Tom F. DesOrmeaux process accomplishes these tasks in an unprecedented fashion.

The Tom F. DesOrmeaux Technology (HT-5 Thermal Distillation Process), subjects hazardous waste to electrically generated heat in a nitrogen atmosphere. The HT-5 distillation system is designed to vaporize compounds via three segregated distillation chambers and recover, via condensation, the segregated effluents (e.g. oil, water, and solids). This dynamic process, therefore, can be utilized for the purpose of segregating any

hazardous compound with a boiling point of 100 degrees F. to 2100 degrees F. from the non-hazardous compounds in a waste product.

In June, 1989, Tom DesOrmeaux licensed the technology to Browning Ferris Industries for use in the forty-eight (48) contiguous states of the U.S.A. In addition, T.D.I. Services, Inc. was issued the license to construct the HT-5 and offer technical support for its various applications.

PROCESS DESCRIPTION

The HT-5 Thermal Distillation Unit is designed to meet the highest standards of construction and safety. All electrical systems are designed to Class 1, Group D, Division 2 specifications. All piping follows ANSI D31.3 guidelines, and all pressure vessels are designed in accordance with ASME Section 8.

The process accepts contaminated hydrocarbon bearing waste in an initial dump bin. Hydraulic powered augers transport the waste into a feed silo where further mixing and equalization of flow occurs. At this point, a nitrogen atmosphere is introduced and the entire system is sealed until the segregated effluents leave the system. The feed silo utilizes a transfer auger to, again, transfer the waste into a feed hopper where it is apportioned to three parallel distillation sections. (See Diagram #1).

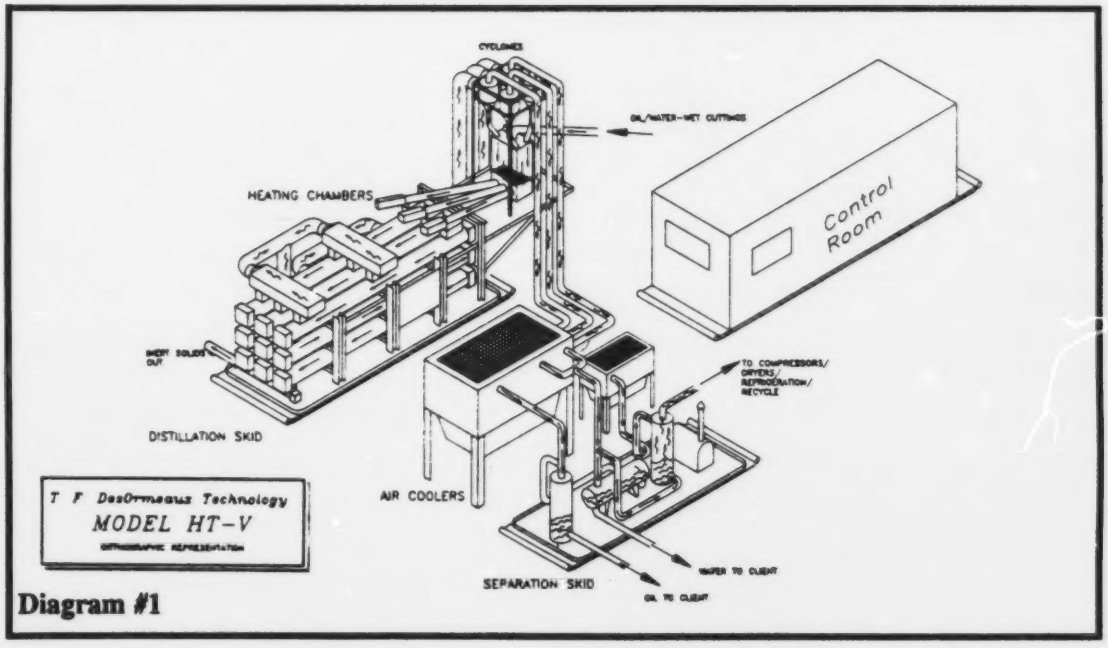

Diagram #1

By using gravity and a system of annular augers, the waste is transferred through three externally heated distillation heating chambers which operate in series. (See Diagram #2.) The continuous introduction of a nitrogen sweep gas creates a low pressure (below atmospheric) condition. This atmosphere prevents combustion/oxidation and facilitates the rapid vaporization of volatile and semi-volatile compounds.

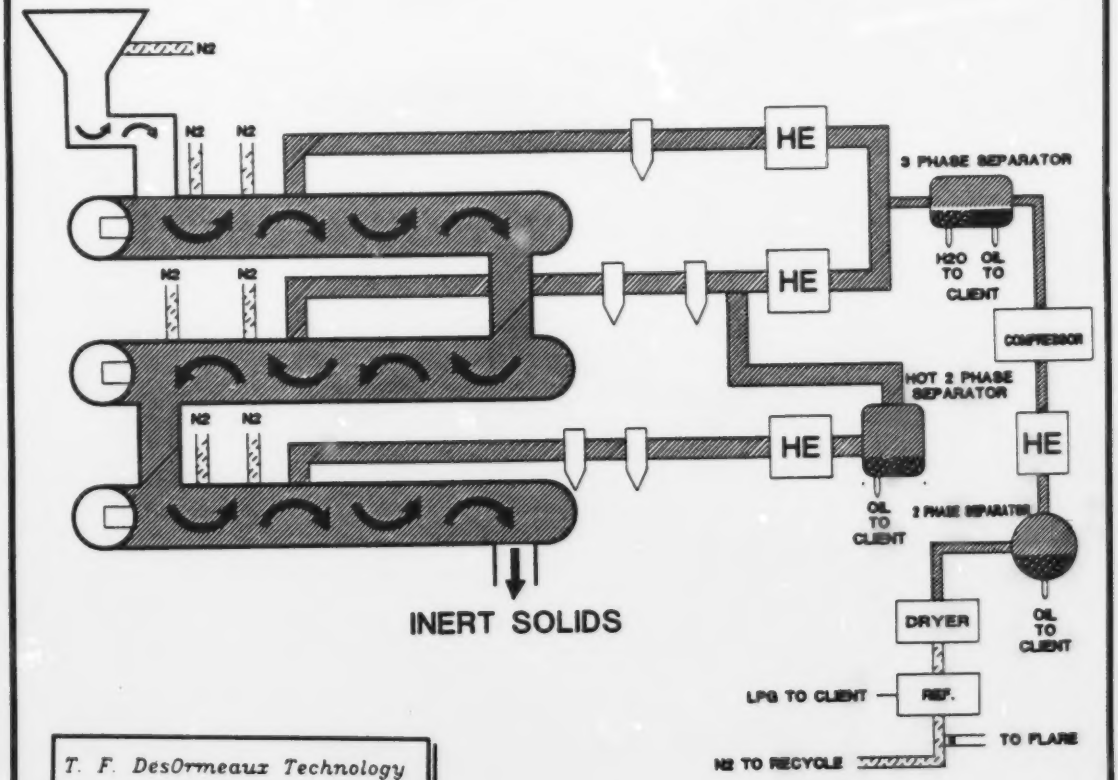

Diagram #2

The waste temperatures and resulting conditions for each of the three heating chambers are as follows:

PROCESS SECTION	WASTE TEMPERATURES	RESULTS
Zone #1	Ambient to 400° F.	Volatilization of water & light hydrocarbons
Zone #2	400° F. to 900° F.	Volatilization of remaining water and light hydrocarbons
Zone #3	900° F. to 2100° F.	Volatilization of remaining hydrocarbons

Specific operating temperatures vary with each waste stream; however, the ability to operate at up to 2200 degrees F. results in maximum efficiency and versatility.

Exact temperatures, pressures, and flows are electronically monitored and controlled via over 1000 separate points throughout the HT-5 process. Data is represented in a graphics-based operator interface system.

The final inert solid effluent stream leaves the HT-5 through an exit port after the third heating chamber and is transported by a conveyor cooling auger to a collection bin for ultimate disposal. The gases from each distillation chamber are sent to a cyclone/dust control system for particle removal. After the cyclones, the gases are gathered and moved through an air cooled condenser, which lowers the gas temperature to 20 degrees F. above ambient air temperature. A series of two- and three- phase separators segregate three different liquid fractions from the remaining gases. The degree of separation can be increased or decreased and is dependant upon the application and required specifications.

The light and heavy oils, as well as other recyclable materials, can be returned to the customer, separately or combined, to be used as fuel oil or refinery feed stock. Recovered water is typically returned to the customer's API Separator or further treated for ultimate discharge.

The remaining gases from the separation process are then compressed, dried, and refrigerated at -30 degrees F. in order to recover liquefied petroleum gases (LPG's) which are also returned to the customer. The remaining nitrogen-rich gases are recycled with a small percentage being sent to flare or a fuel gas system.

APPLICATIONS

The HT-5 Thermal Distillation system is ideally suited for and capable of treating materials with solid contents ranging from 10% to 90% and wastes with oil contents ranging from 0% to 60%. The system will readily accept and process solids ranging in size from sub-micron up to 1.5 inches. Consequently, the versatility of the process allows for its application to a wide variety of waste products.

The HT-5 system's modular characteristics allow for the sizing of the system based on site specific throughput requirements. Typical throughput capacities range between 30 tons and 400 tons per day.

Specific applications for the process have been identified and full scale, as well as pilot scale treatability tests, have been performed. These applications are E.P.A. listed refinery wastes KO-48 through KO-52, creosote contaminated soils, hydrocarbon contaminated soils, mercury contaminated soils, and oil and gas exploration wastes. Analytical data generated from processing these hazardous wastes document that the processed inert solid effluent contains non-detectable concentrations of volatile and semi-volatile hydrocarbons. This degree of hydrocarbon removal will allow for the continued land disposal of refinery wastes beyond the August, 1990 land ban date.

The benefits of the process are numerous. When applied to refinery wastes, the benefits include:

1) The system's reuses of the nitrogen sweep gas resulting in the process possessing an insignificant source of air emissions.

2) Over 99.9% oil removal and subsequent recovery.

3) No oxidation of heavy metals.

4) The ability to exceed land ban parameters on refinery wastes.

5) The process can be utilized as a recycling/resource recovery system and can qualify for exemptions from Federal and State treatment permits in a variety of applications.

CASE STUDY/DEMONSTRATION

A comprehensive case study/demonstration has been performed utilizing the HT-5 Thermal Distillation system. The rated throughput capacity of the demonstrated system is thirty (30) tons of sludge per day. The demonstration was witnessed by a major oil company as well as a third party consulting firm, Law Environmental. As an unbiased third party, Law

Environmental's task was to insure that all samples were collected and analyzed according to an approved Quality Assurance Project Plan. In addition, Law Environmental applied a QA/QC concept encompassing sample collection through data validation.

WASTE DESCRIPTION

T.D.I. Services, Inc. demonstrated the HT-5's hydrocarbon removal and recovery capabilities by processing simulated refinery API separator sludge. The simulated waste was prepared by adding approximately fifteen (15) percent Alaskan North Slope crude oil to oil-based drill cuttings. Top soil, diatomaceous earth, and drilling gel were also added in order to raise the solid content and further emulsify the mixture.

ANALYTICAL DATA

Five separate sample sets of the waste and inert solid effluent were obtained during two consecutive days of operation. As Tables 1 & 2 indicate, three (3) of the five (5) treated residue samples show non-detectable concentrations of volatile, base/neutral, and acid extractable hydrocarbons. The data also shows that the lower processing temperatures associated with samples three (3) and four (4) did not result in complete hydrocarbon removal even though the concentrations observed are well below the land ban criteria. (Specific operating temperatures are considered confidential by T.D.I. Services, Inc..)

In addition to the samples represented in Tables 1 & 2, numerous other samples were obtained including recovered oil, recovered water, recycled sweep gases, and flare gases.

The on-line gas chromatograph analyses of the sweep gases (which are representative of the gases going to flare) indicated no hydrocarbons at a detection limit of ten (10) ppm (v/v) for ethane. The Tenax sorbent samples, collected immediately after the GC analysis were performed, were then analyzed several days later by GC-MS. The samples contained no detectable volatile organic compounds at a detection limit of 0.25 ppm. The particulate emission levels, monitored at the flare, were well below the allowable Texas Air Control Board Regulations for particulate emission rates from any source.

Oil and water sample analyses indicate efficient recovery. The quality of the oil and water is such that the water can be returned to the API Separator and the oil can be returned to the refinery for refinement.

SUMMARY

The HT-5 Thermal Distillation system performed as designed and as represented. The demonstration not only documented the ability to meet the E.P.A.'s land disposal restrictions; it was demonstrated that the total removal and recovery of hazardous hydrocarbon constituents from both simulated refinery waste and oil-based drilling wastes can readily be achieved.

Waste retention time and the amount of Btu's subjected to the waste are the two (2) parameters that control the degree of removal and subsequent recovery of various constituents. It was demonstrated that both parameters can be controlled to an unprecedented degree. Therefore, as the numerous pilot scale treatability studies indicate, the majority of the hydrocarbon contaminated wastes generated by the petroleum industry and the wood treating industry can be processed by the HT-5 High Temperature Thermal Distillation system. The HT-5 Thermal Distillation system will render the inert solid effluent stream acceptable for land disposal and will allow for the recovery of valuable and reusable hydrocarbons.

A simple and effective rule of thumb to expeditiously evaluate the applicability of the technology to a specific waste is as follows:

1. Do the "hazardous" constituents have a boiling point in the range of ambient to 2000 degrees F.?

2. Can particle size ranges of sub-micron up to 1.5 inches be achieved?

3. Is the liquid concentration in the waste less than ninety-five (95) percent?

If the answers to all of the preceding questions are yes, the HT-5 Thermal Distillation is most likely the solution for waste management. The versatile characteristics of the HT-5 Thermal Distillation system is the key to implementing the technology on various wastes/applications.

PILOT SCALE TREATABILITY STUDIES

T.D.I. Services, Inc. has performed numerous treatability studies via the HT-5 Pilot Scale Unit (P.S.U.). P.S.U. treatability studies have been performed on a number of refinery generated wastes, Superfund creosote contaminated wastes, mercury contaminated soils, as well as oil-based drilling wastes. Every study performed has demonstrated that the removal and subsequent recovery of the specified contaminant was achieved.

The P.S.U. utilizes a single heating chamber in which waste is subjected to indirect heat and the nitrogen sweep gas. The temperature and sweep gas volumes are varied and controlled in order to determine the parameters required to produce acceptable constituent removal. The P.S.U. also utilizes three (3) vapor condensing stages for further evaluation. Gases which do not condense are monitored and analyzed with the use of a Gas Chromatograph. Typical sample sizes required to perform studies are two-three (2-3) kilograms of waste.

In order to document the design equivalency and the ability of the P.S.U. to provide scale-up data correlating to the treatment capability of the full scale HT-5 Thermal Distillation system, a study paralleling the full scale demonstration was performed. The study was performed on a split waste sample obtained during the full scale HT-5 demonstration. The analytical results are represented in Table 1. The results from the study indicate that the P.S.U. does, in fact, allow for the comprehensive evaluation of the HT-5's capabilities as applied to various wastes.

There are numerous other applications for the technology. The applications currently being reviewed include dioxins, furans, spent activated carbon, municipal wastes, radioactive mixed wastes, asbestos, synthetic rubber, and tires.

Industries which are potential candidates for the technology are as follows:

Agricultural Chemicals
Lumber & Wood Products
Machinery & Mechanical Service Industry
Nuclear Facilities
Organic Chemicals
Paints & Allied Products
Petroleum & Coal Distribution Industry
Petroleum Exploration
Petroleum Refining
Pharmaceuticals
Plastics Materials & Resins
Pipeline Industry
Pulp & Paper
Soaps and Detergent Industry
Surface Active Agents
Synthetic Rubber
Textile Mills

Currently, there are treatability studies planned for wastes contaminated with dioxins, PCB's, furans, chlorinated phenols, and mixed radio active wastes.

TABLE 1
LAW ENVIRONMENTAL CASE STUDY (EXCERPT)

PARAMETERS	HT-5 #1 Feedstock 1/23/90 14:45	HT-5 #1 Treated Residue 1/23/90 15:05	HT-5 #2 Feedstock 1/23/90 19:15	HT-5 #2 Treated Residue 1/23/90 19:48	HT-5 #3 Feedstock 1/24/90 09:05	HT-5 #3 Treated Residue 1/24/90 09:45
Oil & Grease (ug/g)(wet weight)	139,600.0	62.8	146,000.0	97.0	137,300.0	187.0
pH	8.0	10.2	7.7	10.1	7.5	8.9
Specific Gravity, g/ml (Density)	1.53	2.37	1.60	2.37	1.48	2.06
Water, Karl Fisher, %	24.6	0.4	23.3	0.2	29.8	4.8
Volatiles (mg/kg):						
Acetone	<12.5	<0.010	<12.5	<0.010	<12.5	<0.010
Acrolein	<25.0	<0.020	<25.0	<0.020	<25.0	<0.020
Acrylonitrile	<25.0	<0.020	<25.0	<0.020	<25.0	<0.020
Benzene	284.0	<0.005	282.0	<0.005	285.0	<0.005
Bromodichloromethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Bromoform	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Bromomethane	<12.5	<0.010	<12.5	<0.010	<12.5	<0.010
2-Butanone	<25.0	<0.020	<25.0	<0.020	<25.0	<0.020
Carbon disulfide	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Carbon tetrachloride	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Chlorobenzene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Chloroethane	<12.5	<0.015	<12.5	<0.010	<12.5	<0.010
2-Chloroethylvinyl ether	<25.0	<0.020	<25.0	<0.020	<25.0	<0.020
Chloroform	<6.25	0.005	<6.25	0.010	<6.25	<0.005
Chloromethane	<12.5	<0.015	<12.5	<0.010	<12.5	<0.010
Dibromochloromethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Dibromomethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
1,4-Dichloro-2-butene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Dichlorodifluoromethane	<12.5	<0.015	<12.5	<0.010	<12.5	<0.010
1,1-Dichloroethene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
1,2-Dichloroethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
1,1-Dicloroethene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
trans-1,2-Dichloroethene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
1,2-Dichloropropane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
cis-1,3-Dichloropropene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005

TABLE 1 (cont.)

PARAMETERS	HT-5 #1 Feedstock 1/23/90 14:45	HT-5 #1 Treated Residue 1/23/90 15:05	HT-5 #2 Feedstock 1/23/90 19:15	HT-5 #2 Treated Residue 1/23/90 19:48	HT-5 #3 Feedstock 1/24/90 09:05	HT-5 #3 Treated Residue 1/24/90 09:45
trans-1,3-Dichloropropene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Ethanol	<25.0	<0.025	<25.0	<0.020	<25.0	<0.020
Ethyl benzene	290.0	<0.005	312.0	<0.005	249.0	<0.005
Ethyl methacrylate	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
2-Hexanone	<25.0	<0.020	<25.0	<0.020	<25.0	<0.020
Iodomethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Methylene chloride	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
4-Methyl-2-pentanone	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Styrene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
1,1,2,2-Tetrachloroethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Tetrachloroethene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Toluene	617.0	<0.005	630.0	<0.005	644.0	0.005
1,1,1-Trichloroethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
1,1,2-Trichloroethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Trichloroethene	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Trichlorofluoromethane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
1,2,3-Trichloropropane	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Vinyl acetate	<6.25	<0.005	<6.25	<0.005	<6.25	<0.005
Vinyl chloride	<12.5	<0.010	<12.5	<0.010	12.50	<0.010
m-Xylene	240.0	<0.005	243.0	<0.005	242.0	<0.005
o,p-Xylene	595.0	<0.005	606.0	<0.005	624.0	<0.005
Base/Neutrals (mg/kg):						
Acenaphthene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Acenaphthylene	<9.8	<0.10	<9.8	<0.099	<10.0	0.56
Acetophenone	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Aniline	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Anthracene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.63
4-Aminobiphenyl	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Benzidine	<19.6	<0.20	<19.6	<0.20	<20.0	<0.20
Benzo(a)anthracene	<9.8	<0.10	<9.8	<0.099	<10.0	0.36
Benzo(b)fluoranthene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10

TABLE 1 (cont.)

PARAMETERS	HT-5 #1 Feedstock 1/23/90 14:45	HT-5 #1 Treated Residue 1/23/90 15:05	HT-5 #2 Feedstock 1/23/90 19:15	HT-5 #2 Treated Residue 1/23/90 19:48	HT-5#3 Feedstock 1/24/90 09:05	HT-5#3 Treated Residue 1/24/90 09:45
Benzo(k)fluoranthene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Benzo(g,h,i)perylene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Benzo(a)pyrene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Benzyl butyl phthalate	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Bis(2-chloroethoxy)methane	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Bis(2-chlorethyl)ether	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Bis(2-chloroisopropyl)ether	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Bis(2-ethylhexyl)phthalate	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
4-Bromophenyl phenyl ether	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
4-Chloroanaline	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
1-Chloronaphthalene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2-Chloranaphthalene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
4-Chlorophenyl phenyl ether	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Chrysene	<9.8	<0.10	<9.8	<0.099	<10.0	0.53
Dibenzo(a,j)acridine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Dibenzo(a,h)anthracene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Dibenzofuran	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Di-n-butyl phthalate	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
1,2-Dichlorobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
1,3-Dichlorobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
1,4-Dichlorobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
3,3'-Dichlorobenzidine	<19.6	<0.20	<19.6	<0.20	<20.0	<0.20
Diethyl phthalate	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Dimethyl phthalate	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
p-Dimethylaminoazobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
7,12-Dimethylbenz(a)anthra	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
a,a-Dimethylphenethylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,4-Dinitrotoluene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,6-Dinitrotoluene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Di-n-octyl phthalate	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Diphenylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10

TABLE 1 (cont.)

PARAMETERS	HT-5 #1 Feedstock 1/23/90 14:45	HT-5 #1 Treated Residue 1/23/90 15:05	HT-5 #2 Feedstock 1/23/90 19:15	HT-5 #2 Treated Residue 1/23/90 19:48	HT-5#3 Feedstock 1/24/90 09:05	HT-5#3 Treated Residue 1/24/90 09:45
1,2-Diphenylhydrazine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Fluoranthene	<9.8	<0.10	<9.8	<0.099	<10.0	0.79
Fluorene	10.8	<0.10	14.4	<0.099	<10.0	0.27
Hexachlorobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Hexachlorobutadiene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Hexachlorocyclopentadiene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Hexachloroethane	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Indeno(1,2,3,cd)pyrene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Isorphorone	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
3,Methylcholanthrene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2-Methylnaphthalene	153.0	<0.10	185.0	<0.099	150.0	0.36
Methel methanesulfonate	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Naphthalene	87.9	<0.10	93.7	<0.099	84.8	0.54
1-Naphthylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2-Naphthylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2-Nitroanaline	<39.2	<0.40	<39.2	<0.40	<40.0	<0.40
3-Nitroanaline	<39.2	<0.40	<39.2	<0.40	<40.0	<0.40
4-Nitroanaline	<39.2	<0.40	<39.2	<0.40	<40.0	<0.40
Nitrobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
N-Nitrosodi-n-butylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
N-Nitrosodimethylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
N-Nitrosodi-n-propylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
N-Nitrosodiphenylamine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
N-Nitrosopiperidine	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Petachlorobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Pentachloronitrobenzene	<19.6	<0.20	<19.6	<0.20	<20.0	<0.20
Phenacetin	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Phenanthrene	36.7	<0.10	45.1	<0.099	35.5	2.2
2Picoline(2-methylpyridine)	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Pyrene	<9.8	<0.10	<9.8	<0.099	<10.0	1.4
1,2,4,5-Tetrachlorobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10

TABLE 1 (cont.)

PARAMETERS	HT-5 #1 Feedstock 1/23/90 14:45	HT-5 #1 Treated Residue 1/23/90 15:05	HT-5 #2 Feedstock 1/23/90 19:15	HT-5 #2 Treated Residue 1/23/90 19:48	HT-5 #3 Feedstock 1/24/90 09:05	HT-5 #3 Treated Residue 1/24/90 09:45
1,2,4-Trichlorobenzene	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
Acid Extractables (mg/kg):						
Benzoic acid	<49.0	<0.50	<49.0	<0.50	<50.0	<0.50
Benzyl alcohol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
4-Chloro-3-methylphenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2-Chlorophenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,4-Dichlorophenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,6-Dichlorophenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,4-Dimethylphenol (Xylenol)	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,4-Dinitrophenol	<49.0	<0.50	<49.0	<0.50	<50.0	<0.50
2-Methyl-4,6-dinitrophenol	<49.0	<0.50	<49.0	<0.50	<50.0	<0.50
2-Methylphenol (o-Cresol)	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
4-Methylphenol (p-Cresol)	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2-Nitrophenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
4-Nitrophenol	<49.0	<0.50	<49.0	<0.50	<50.0	<0.50
Pentachlorophenol	<49.0	<0.50	<49.0	<0.50	<50.0	<0.50
Phenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,3,4,6-Tetrachlorophenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,4,5-Trichlorophenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10
2,4,6-Trichlorophenol	<9.8	<0.10	<9.8	<0.099	<10.0	<0.10

INTERNATIONAL ASPECTS OF WASTE MANAGEMENT, AND THE ROLE OF THE UNITED NATIONS ENVIRONMENT PROGRAMME (UNEP)

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Introduction

The production of oil and gas industry is indisputably a world scale industry, whatever criteria we use. With an annual production of around half of the world's energy demand the industry employs thousands persons worldwide, and transports large quantities of product over long distances. Oil companies are the largest of the multinationals, with diversified activities worldwide.

This importance carries over into the environmental sector. The environmental impacts of the industry are considerable, whether in terms of size of individual accidents, or in aggregated volumes of residues released from normal operation. The industry features prominently in the environmental literature. And among the environmental issues confronting the industry waste management is near the top of the list.

Waste management is however a fairly loose term. Depending on one's point of view it can range from standard notions of disposal of production residues to also include clean-up of spills, site reclamation, and control of air emissions. It can even extend to release of carbon dioxide, which is beginning to affect our climate. As cradle to grave concepts of waste management now consider the impact from products themselves, the conception, use and disposal of the products of the industry is brought into question.

However it is not only the scientifically predicted ecological impact that is important to waste management. National perceptions to pollution issues vary greatly, and are often coloured by perceptions

of who and where the causes of such pollution are. We should not be surprised that there is a high intolerence to pollution impacts imposed from abroad. From the NIMBY syndrome we already know that there is a resistance to accept local impacts for the sake of beneficiaries who are far away.

While the cause and effects of environmental impact can be readily identified, those who are concerned with putting the global house into better order are less well known. It is the purpose of this paper to outline some of these actors, and the scope of their programmes, in the hope that better knowledge will also eventually encourage better contributions to, and enhanced performance of, global initiatives of waste management in the oil and gas sector.

Waste Management Issues of International Concern

Let us briefly look at some of the most significant international issues which are relevant to the management of wastes.

Waste dumping in international waters is one of the most visible and controversial environmental issues wordwide. Wastes which are currently dumped at sea include toxic chemicals, sludges, muds and solid waste, oily bilge waters and ship cleaning wastes, and garbage. Derelict offshore structures, debris and equipment left on the sea-bed interferes with fishing and other uses. All these add up to a significant problem in the marine environment, with many impacts also felt on the coast.

A particularly pernicious aspect of waste disposal in recent years has been the trade in industrial waste which we cannot, or will not, dispose of at home. The argument to support such trade is sometimes dressed up in the purported economic benefits to the recipient country, or that in such and such a place the effect is not harmful. The motives however are seldom that benign. No-one engages in waste trade for reasons of charity. Recipient countries are as stigmatized by this practice (even if it were to be made technically sound, which it never is) as would be our own communities if they were to be the destination.

Waste dumping is a particular example of the larger issue of unequal environmental practices adopted abroad by multinational companies. While many large companies have now moved to redress this disparity, it remains to be seen how such policies influence also their contractors, supply agents, and local business partners.

Improved management of wastes has also become a component of larger trade issues. Transfer of technology to developing countries is a

sensitive issue on which there is as yet no consensus. Cleaner production processes and better treatment methods are included in the technology transfer agendas. Better access to, and favorable terms for purchase of, such technologies is increasingly demanded in international negotiations.

The newest and most controversial transnational issue is that of climate change. The link between global warming and industrial emissions is now strong enough to justify action. As the greatest part of the world production of oil and gas is burnt as a fuel, the industry's contribution to anthropogenic CO_2 is not negligible. Other emission products such as SO_2 may contribute to the regional occurence of acid rain.

All the above must of course be seen in the context also of local impact from waste disposal operations. In most instances the local effects are the most acute. Local disposal practices determine the extent of the impact there on humans and the ecology, including the protection of human living resources. Good management at the local level will often (but not always - remember the tall stacks policy) avoid also international problems.

Addressing International Issues - Institutions, Responsibilities, Programmes.

In considering how environmental problems are best resolved it is necessary to keep in mind the diverse nature of the industry, and its ubiquitous location. Large multinationals have the skills, the technology, the financial means, and the organization necessary to take remedial action. Smaller companies lack some of these attributes and therefore contribute less well. In developing countries also, a simultaneous shortage of information, technology and organization inhibits effective action, exacerbated by a generally lower level of management awareness of the need to do so. This leaves the problems at the local level more acute, and simultaneously less of a contribution is made to international action. Overcoming such constraints is an important part of international environmental programmes.

In order to address problems of global dimensions we often need new procedures, and new organizations. National regulations and administrative procedures are difficult to apply in the international arena without extensive modification. New legal structures have therefore been created to fill the gap. A number of international conventions and agreements already exist for the marine environment, for hazardous waste, and more recently for protection of the atmosphere. Implementation of international agreements however rests

with national agencies, using new provisions under national legislation.

An example of a successful convention is the London Dumping Convention. This specifically states what can and what cannot be dumped at sea by the signatory parties. The convention has recently moved to also address land-based sources of pollution. Other more regional conventions apply to the North Sea, the Baltic, and the Mediterranean, and cover such issues as ocean dumping and land-based sources of pollution. Another convention, MARPOL, is well known by ship owners.

Of special interest in hazardous waste management is the Basel Convention (see annex 1). This limits international trade in hazardous waste, and addditionally makes a strong demand for less waste to be produced, and for residues to be disposed of as close to the point of generation as possible. There are now also proposals for a forthcoming convention on climate change, which could include a limitation on CO_2 production. A number of countries have already pledged to limit future CO_2 emissions.

Conventions and codes of practice are useful in agreeing on goals, but they are less specific about how the goals are achieved. National legislation and company programmes to implement conventions vary greatly in format and in substance. Each country is constrained by its political and legislative system, and of course by consideration of economic implications. While developing countries contribute their share of waste problems, they often lack many of the technical and managerials skills to overcome them, and frequently do not have the economic means that are available to industrialized nations.

While not yet extensively subject to international agreement (or perhaps because of this lack) the question of disparity in applied environmental standards needs to be tackled more creatively. There is a much greater diversity of global circumstances than is found at the national level. We need to be clear about the implications of "equal regulatory standards", whether applied by a government or by a company. Equal <u>standards</u> may not always be appropriate. What is actually required is equal environmental goals, and equal environmental performance, defined according to local objectives, but consistent with wordwide practice.

A simple example will suffice. A company environmental policy that assumes the availability of skilled disposal contactors may work well in the US or in Europe, but is totally inappropriate in most developing countries. A policy of equal environmental performance implies a proportionally greater degree of company self-reliance where

infrastructure is poor. A policy of equal standards merely passes the buck to someone unprepared to handle it.

A prerequisite to the adoption of conventions and standards are activities such as technical assistance and information transfer. These activities are essential if individual corporations and government agencies, especially in developing countries, are to act effectively and cohesively.

Most intergovernmental organizations already incorporate environmental considerations, and quite a few have explicit environmental assistance and information programmes. In many cases environment is not their only responsibility, however. UNEP was created in 1972 as a co-ordinating agency to harmonize the environmental initiatives of UN agencies. Along the way UNEP launched international monitoring programmes such as GEMS, and an information exchange system based on INFOTERRA. A regional seas programme specifically addresses the marine environment. The Industry and Environment Office (IEO) as its name implies deals specifically with issues relevant to industry. Waste management through cleaner production and proper disposal are key elements of its programme.

Industry has itself created several organizations to focus on environmental issues. The International Chamber of Commerce (ICC), and through its influence the International Environmental Bureau (IEB), deal with all industry sectors. The oil industry has created the International Petroleum Industry Environmental Conservation Association (IPIECA) and the Oil Companies' European Organization for Environmental Health Protection (CONCAWE) for example as international co-ordinating and information exchange bodies, and serve as an environmental focal point for the industry as a whole. The tanker owners have formed a "pollution" federation. These associations participate in discussions on conventions, but have also taken some measures of their own to induce their members to exercise voluntary restraint on environmentally damaging activities. This is usually by way of codes of practice or technical guidelines. On an overall industry basis the ICC prepared some time ago a policy statement on environmental management.

<u>UNEP/IEO - Its role, programmes and activities as relevant to the oil and gas industry</u>

The Industry and Environment Office within UNEP was established in 1975, and is located in Paris, France. IEO has the specific task of bringing industry and government together to ensure a sustainable, non-polluting industrial development.

Without neglecting more general specific pollution issues, IEO has concentrated particularly on a number of strategic areas which help to systematically reduce environmental impact. These strategic areas include:

- waste avoidance through promotion of information networks on cleaner production processes, safer chemicals, and low-impact products,

- proper methods of managing hazardous wastes in all industries,

- awareness and preparedeness by local communities of possible industrial accidents (APELL),

- adoption by industry of strategic environmental management tools such as environmental auditing, environmental performance goals, waste minimization programmes, and personnel training in environment.

How does IEO function? IEO's role is to inform, co-ordinate and stimulate others to take the initiative. IEO deals directly with both governments and with industry in pursuing the above. Industry sectors where IEO has already worked include chemicals, oil, leather, and minerals. IEO also works with other relevant international and regional organizations such as UNIDO, ISWA etc.

In its role as a catalyst for others to take action, IEO activities are concentrated in four major directions:

(i) publishing **technical guidelines** on important industry sectors, key environmental issues, and useful management tools (see annex 2),

(ii) facilitating direct **information exchange** through its quarterly journal "Industry and Environment", and through a query-response service,

(iii) supporting **training** workshops and on-the-job training projects,

(iv) arranging **technical co-operation** by way of studies, expert missions and seminars.

Many of these initiatives are pursued jointly with other interested organizations or sponsors. Technical assistance from industry and government experts often underpins the practical work projects carried out.

For example, industry provides some of the expert resource persons for training workshops, or for technical co-operation missions to developing countries. Through expert group meeting at IEO or elsewhere industry makes available its management experience in the environmental area. In assisting with technical queries, as for example also through the IEB, industry shares some of its environmental know-how with others. Conferences and seminars on waste management or other topics are sometimes sponsored by the industry sector.

Complementary activities are also carried out by other UNEP divisions. These include chemical safety (IRPTC and IPCS), hazardous waste conventions (ELIU, IRPTC), technical information sources (INFOTERRA), environmental monitoring and climate change (GEMS), and marine pollution (OCA-PAC). Other divisions and regional offices play a vital supporting role.

A particularly important recent role is that of the (interim) secretariat of the Basel Convention. The secretariat has the role of both guiding, and monitoring, activities in the signatory countries. The secretariat is located in Geneva, Switzerland.

Application to the Oil and Gas Industry

Although many company managers are already aware of the environmental impacts of their industry, and have taken measures to reduce them, considerable further effort is still necessary within the industry.

Initiatives of cleaner production, ie. waste minimization could be particularly strengthened, especially in developing countries but also in the West. In this respect the role of multinationals in guiding their affiliates in other countries is particularly important.

The commendable principle of self-regulation could be given greater effect, first by expanding membership and activity within international associations, and subsequently developing comprehensive codes of practice. The question of monitoring and enforcing members' actions on such codes has always been a delicate one for industry associations, but is nevertheless an essential part of regulation, whether self or otherwise.

At the company level a more widespread elaboration of strong environmental policies would reinforce among all personnel, and among contractors and clients, that proper waste management is an inseparable part of doing business in the 90's, and not merely a peripheral nuisance.

A strong boost needs to be given to our less fortunate colleagues in developing countries. An expansion of assistance programmes is needed, with contributions from the industry sector as well as from government. Bi-lateral programmes are effective in reinforcing existing links; multilateral programmes such as through UNEP/IEO reach a more general audience. In this respect IEO would welcome increased participation in, and contributions to, its initiatives to help less prepared nations to implement the same practices and standards that are now in force in the more aware industrialized countries.

Among the initiatives that IEO sees appropriate in the oil and gas sector are:

- the preparation of further sector specific technical guides that consider appropriate cleaner technological processes, and management operations. Guides could cover specified operations, or issues, or management tools,

- building up a bibliography of relevant technical information on cleaner production methods, and on environmental legislation relevant to the industry. This could be included in the International Cleaner Production Information Clearing House (ICPIC) data network now being established by IEO with the co-operation of the US EPA. Contributions to such a project could come both from individual corporations, and through existing international industry associations,

- joint work on developing further relevant industry codes of practice and guidelines on for example marine pollution, waste dumping, and global climate change issues,

- providing assistance such as training and technical co-operation to other international organizations and national entities. Among the audiences in need of such assistance are government planners, industrialists and local consultants.

Annex 1

Main Points of the Basel Convention

1. A signatory State cannot send hazardous waste to other signatory States that ban its import or to non-signatory countries.

2. No signatory country may ship hazardous waste to another signatory State if the importing country does not have the facilities to dispose of the waste in an environmentally sound manner.

3. Every country has the sovereign right to refuse to accept a shipment of hazardous waste.

4. Before an exporting country can start a shipment on its way it must have the importing country's consent in writing. The exporting country must first provide detailed information on the intended export to the importing country to allow it to assess the risks.

5. Less hazardous waste should be produced. Residues should be disposed of as close to their source as possible.

6. If importing countries cannot dispose of imported waste in an environmentally acceptable way, exporting States must take it back for environmentally sound disposal elsewhere.

7. Illegal traffic in hazardous waste is criminal.

8. Shipments of hazardous waste must be packaged, labelled, and transported in conformity with generally accepted and recognized international rules and standards.

9. Bilateral agreements by signatory States with each other and with a non-signatory countries must conform to the terms of the Convention and be no less environmentally sound.

10. As authorities in developing countries may lack trained specialists and know-how to assess information about hazardous waste greater international co-operation is required to train technicians, to exchange information, and for the transfer of technology.

11. A secretariat is to be set up to supervise and facilitate the implementation.

12. Signatory parties will report annually about transboundary movements of hazardous wastes in which they have been involved.

Annex 2

Some Publications of the UNEP Industry and Environment Office

Periodicals

- "Industry and Environment" - a quarterly review dealing with a wide range of topics and issues. Subscription US $ 45 p.a.
- Cleaner production - Quarterly, free
- APELL Newsletter

Monographs

1. Environmental Management Practices in Oil Refineries and Terminals
2. Environmental Aspects of Oil Exploration and Exploitation (currently being prepared)
3. Impact of Water-based Drilling Mud Discharges on the Environment
4. Environmental Auditing
5. Storage of Hazardous Materials
6. Apell - Awareness and Preparation for Emergencies at the Local Level: a process for responding to technological accidents

Other UNEP Publications

7. The Cairo Guidelines and Principles for the Environmentally Sound Management of hazardous Wastes (1987)
8. The Basel Convention on the Control of Transfrontier Movements of Hazardous Wastes and their Disposal (1989)
9. Treatment and Disposal Methods for Waste Chemicals (IRPTC)
10 The Disposal of Hazardous Wastes: the Special Needs of Developing Countries - 3vols., jointly with the World Bank and WHO
11 Air and Water Pollution: a Directory of Information Sources (INFOTERRA/IEO)

LAND FARMING OF DRILLING MUDS IN CONJUNCTION WITH PIT-SITE RECLAMATION: A CASE HISTORY

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Abstract

Incorporation of fresh water drilling muds in the soil media (Land-Farming) has been practiced in the oil patch for quite sometime. In order to ligitimize the practice, several states have enacted laws, rules and regulations, to meet certain regulatory requirements. Oklahoma adopted its "soil farming" rules during late 1985.

In this project the mud was analyzed for several limiting parameters such as Total Soluble Salts, Oil and Grease and Percent Dry Weight. The salt loading rates were calculated based upon the salinity of receiving soil and the salinity of each batch of drilling mud. An onsite quality control program was established to determine the mud weight, mud viscosity, pH, electrical conductivity, total soluble salts and chlorides to assure compliance with State's regulatory reqirements.

This paper describes the salient features of Oklahoma's regulatory program through a case history of a successful land farming project in conjunction with site reclamation efforts at an off site mud disposal pit in Cater County, Oklahoma. The process was found to be envoron-mentally safe and cost-effective over other available options.

Introduction

Drilling muds are circulated through the well bore during drilling operations to remove the cuttings from down hole and to lubricate, and cool the drill pipe and drill bit. A variety of additives are also mixed with the mud to cure and prevent certain specific conditions deep down in the hole resulting from high temperatures and pressures (1).

In Oklahoma, according to a rule of thumb, drilling operations generate about 2 bbls of spent mud and shale cuttings per foot of drilled depth. Due to continual influx of drilled solids, a portion of the mud is

rejected and jetted out in a reserve pit. The remaining mud is then diluted with water to reduce solid buildup. Other sources of fluids include derrick floor wash resulting from spills when connections are made.

These reserve pits are in use only during the drilling operation and generally remain open for about a year after the drilling is finished. In Oklahoma, in shallow depth areas, the size of a typical reserve pit is generally about an acre in area and contains approximately 5 to 6 feet of fluid. In the deep Anadarko Basin, however, it is not uncommon to have a reserve pit approaching 2 acres in area and a fluid depth of 8 to 10 feet.

In the recent past, considerable attention has been focused on the potential environmental impact of this vast amount of spent mud and the manner in which it is disposed. The concerns range from the possibility of surface soil and water degradation to ground water contamination due to the soluble salts and heavy metals contained in certain types of drilling muds. Oil-based drilling muds pose their own specific concerns to the environment.

Incorporation of freshwater drilling mud in the soil media has been a practice in the oil patch for quite sometime. This paper describes the salient features of Oklahoma's regulatory program through a case history of successful soil-farming project in conjunction with site reclamation efforts at an off-site mud disposal pit in Carter County, Oklahoma. The process was found to be environmentally safe and cost effective over other available options.

Oklahoma's Regulatory Requirements

Existing practices of closing and disposing the reserve pit contents in Oklahoma includes various options. These options are standard industry practices and are available under Oklahoma's regulatory program and include, but are not limited to: (1) evaporation / dewater and backfilling; (2) solidification of pit contents; (3) annular injection; (4) soil-farming; (5) haul-off to a commercial pit facility; (6) haul-off to a commercial soil farming facility (2).

A soil-farming working guideline was issued by the Oklahoma Corporation Commission back on October 7, 1986. Final rules and regulations were adopted on November 10, 1986. Since then there have been several upgrading of those rules and now the program even allows soil-farming of the freshwater drilling muds from a "closed system" steel tanks concurrent to the drilling operations.

The rules and regulations require compliance with a variety of issues and concerns ranging from technical, environmental to operational constraints (see TABLE 1).

The loading criteria are divided into two major categories; one dealing with the physical and chemical properties of the drilling mud and the second dealing with the physical and chemical properties of the receiving soil. In addition to the loading restrictions, several other requirements were introduced and adopted which made the program more effective.

Oklahoma Corporation Commission did not set any limits on maximum chloride concentration on the mud component. However, it is required that the total salt burden in the soil shall not exceed 6000 lbs per acre, which includes the initial salt contents of the receiving soil. Furthermore, since plants respond to the osmotic potential due to total salinity, the effect of chloride is included in the total salt burden restriction (3).

In order to maintain sufficient aeration in the root zone, it was proposed and later adopted that no more than 200,000 lbs of mud (on a dry wt. basis) be incorporated in an acre furrow slice of soil, which contains 2,000,000 lbs of soil (4). Restrictions on toxic elements were also proposed and were adopted. For commercial soil farming operations, chromium is limited to 40 lbs per acre, and arsenic to 80 lbs per acre. No restrictions on barium are in place at this point in time. Hydrocarbons are allowed up to 40,000 lbs per acre or two (2) per cent by weight. The analysis of mud is based on one composite sample for each 25,000 bbls of fluid volume in a pit. For a mud sample to be representative, a composite sample must consist of a minimum of five samples taken from different horizontally and vertically distributed locations in each pit. Restrictions on the receiving soil are presented in TABLE 1.

Carter County Soil-Farming Project

The soil-farming project site is located in the Northeast quarter of Section 21, Township 4 South and Range 2 West in Carter County, Oklahoma (see Fig.1). Figure 1 shows the shape, size and the configuration of the two pits along with the locations of several receiving soil units. These pits were permitted on April 17, 1981 by the Oklahoma Corporation Commission's District Office in Duncan, Oklahoma. These pits togather constitute the "offsite mud disposal facility". Pit dimensions were designed to accomodate the expected volume of spent drilling mud from approximately 30 new unit wells in

Hewitt Field in Oklahoma. The operator, Exxon Corporation, proposed a pit size of 300 ft by 300 ft and fluid depth of 6 feet for each of the two pits in their Permit Application. However, at the time when the project started, the total volume of the mud in two pit was measured to be about 168,000 bbls.

Characterization of the Drilling Mud

Mud sampling as a function of depth was conducted using a Bucket Auger (Soil Test Inc.) for Pit # 1, while an 8 ft. long 2 inch diameter PVC tube, fitted with a closing device, was used to sample the pit contents of Pit # 2 which contained certain amount of top water. This technique allows the mud sample to be composited for various depths as required by the rules and regulations. Chemical analysis of a composite sample of mud from Pit #1 and Pit # 2 is presented in TABLE 2. In addition to that, a detail chemical analysis of the mud samples from Pit # 1 and # 2 was conducted. The data, not presented in this paper but can be made available from the author, indicated that there is a great deal of variation in the salinity level, both horizontally as well as vertically, since there was no particular pattern in the way the mud was dumped into these pits. This variation in salinity required that onsite quality control be maintained for each batch of mud to be soil farmed.

Pit # 1 and Pit # 2 were divided into several "working regions" based upon the chemical make-up of the mud (see Fig.2). In-pit slurry making operations were controlled for horizontal and vertical variability in the salinity level. Mud in each working area was uniformly mixed and analyzed for the most limiting parameter and loading rate calculations before hauled of to the receiving soil Unit. Tank truck crew was instructed and directed to specific land areas in the unit of receiving soil. An accurate record was maintained of the quantity and quality of the mud disposed of at each given location to avoid salt over loading.

Characterization of the Receiving Soils

The "permit area" is dominated by one Soil Type, namely Normangee Loam (# 31) however, a certain amount of Durant Loam (# 11) also occurs in the soil-farmed area (see Fig.3). Soils in these groups consist of well drained deep solum and gently to moderately sloping topography. Normangee Loam has a slope of 2 to 5 per cent. It was formed over a shaley parent material as reflected in the depth profile. This soil is characterized by top 6 inches of loam and 6 to 80 inches of clay. Durant Loam is quite similar also, being loam in top 10 inches and then having a transition layer of clay loam from 10 to 16 in. Rest of

the profile is composed of clay upto 83" deep, similar to Normangee Loam.

Although, the receiving soils were high in sodium, the overall salinity status was low, being only 911 ppm of TDS for GT 2a and 935 ppm for GT 2b soil tracts. The Exchangeable Sodium Percentage (ESP) and Sodium Adsorption Ratio (SAR) as defined in (3) was only 3 units, indicating that the soil has a large assimilative capacity for drilling mud before any sodium hazard is noticed.

Loading Rates for Various Parameters

Loading Rates were calculated according to the formulae adopted by the Oklahoma Corporation Commission. Loading rates of various limiting parametrs for two receiving soil units, namely, GT 2a and GT 2b were determined. It was found that the most limiting parameter in all cases was the Total Dissolved Salt (TDS). Oil and Grease and Percent Dry Wt. were never the limiting factors. Based upon the analysis, it was calculated that the soil unit GT 2a, which contained 37 acres of usable land can assimilate more than 43,000 bbls of mud from the Pit # 2. Similarly, the soil unit # GT 2b, which contained 35 acres of land can be used for another 42,000 bbls of mud from Pit # 2. All calculations were made on mud conditions on an "as is" basis.

From a bench scale model, it was determined that a certain amount of water will be mixed with the mud, to achieve a 9.0 ppg or better mud weight and a Funnel Viscosity of 36 or better to achieve proper rheological properties for its incorporation in the soil. For the purpose of calculating the loading rates, one acre furrow slice of an average soil was taken to be 2,000,000 lbs. Furthermore, for Oil and Grease calculations, an API gravity of 35 was used. Percent Solids were determined on "as is" basis. When needed, the relative density of chromium and arsenic was taken as 7.2 gm/cc and 5.73 gm/cc respectively. Based upon these assumptions, loading rates were calculated on location using a field lab.

Field level quality control and quality assurance

At the field lab, mud weight was determined by weighing a quart of mud to the nearest hundredth of a pound. The mud viscosity was measured using Marsh Funnel for the same quart sample. The sample was then placed in an API Filter Press and an adequate amount of filtrate was extracted at 115 psi pressure. The filtrate was used to determine the pH, Electrical Conductivity, Total Dissolved Salts (TDS) and the Chloride concentration. The results of wet chemistry were used in

loading rate calculations. Data summarizing the daily loading rates for each batch of mud for the soil-farming project can be obtained from the author. A portion of the land was designated for each batch every day. Mud was applied through a spreader bar using a tank-truck operation. With the exception of few accidental spills, all mud was spread uniformly on the designated land. A detailed post-application soil sampling was conducted with in a week. Samples were taken from 0-6" depth for each 2.5 acre land soil farmed. Results of post application soil salinity level are presented in TABLE # 3.

Results and discussion

Results of this study and other previous work (5) indicated that disposal of fresh water drilling mud through the soil-farming option is environmentally safe, cost effective, and does not adversely affects the receiving soils. Data from this study indicated that while the TDS and Cl were high in the pits, they were greatly diluted during the slurry making operations. Chloride concentration ranged between 1,100 ppm to 2,500 ppm for most of the time, exceeding 3000 ppm only once. However, the chlorides were significantly reduced after the soil application due to additional dilution in the soil. Post application chlorides in the soil ranged from 230 ppm to 798 ppm. Similar trends were observed in the total dissolved salts (TDS) data where the concentration ranged from 1088 ppm to 2304 ppm. It is interesting to note, that the maximum salt burden allowed under Oklahoma's program is 6,000 lbs of salt per acre of soil, which is equivalent to 3,000 ppm TDS in the soil. Post application data indicated that the salt burden level in the receiving soil did not exceed even on areas where we had accidental spills. Soil farming, if conducted properly, can be beneficial to certain sandy soils by adding fines to the texture thereby increasing the water holding capacity for plant growth and reducing fertilizer losses. The technique can be effectively used in conjunction with other cleanup and remedial processes for salt water and hydrocarbon spills and pipeline breaks.

Conclusions

Based upon our experience it is concluded that:

1. Soil-farming of fresh water drilling muds and shale cuttings can be safely achieved under proper QA/QC proceedure.
2. It provides an excellent option for "closed system" drilling operations.
3. Shale cuttings from oil-based muds can be effectively soil-farmed. Naturally occuring bacteria in the soil can effectively biodegrade the oil and grease adsorbed on the shale surface.

Acknowledgement

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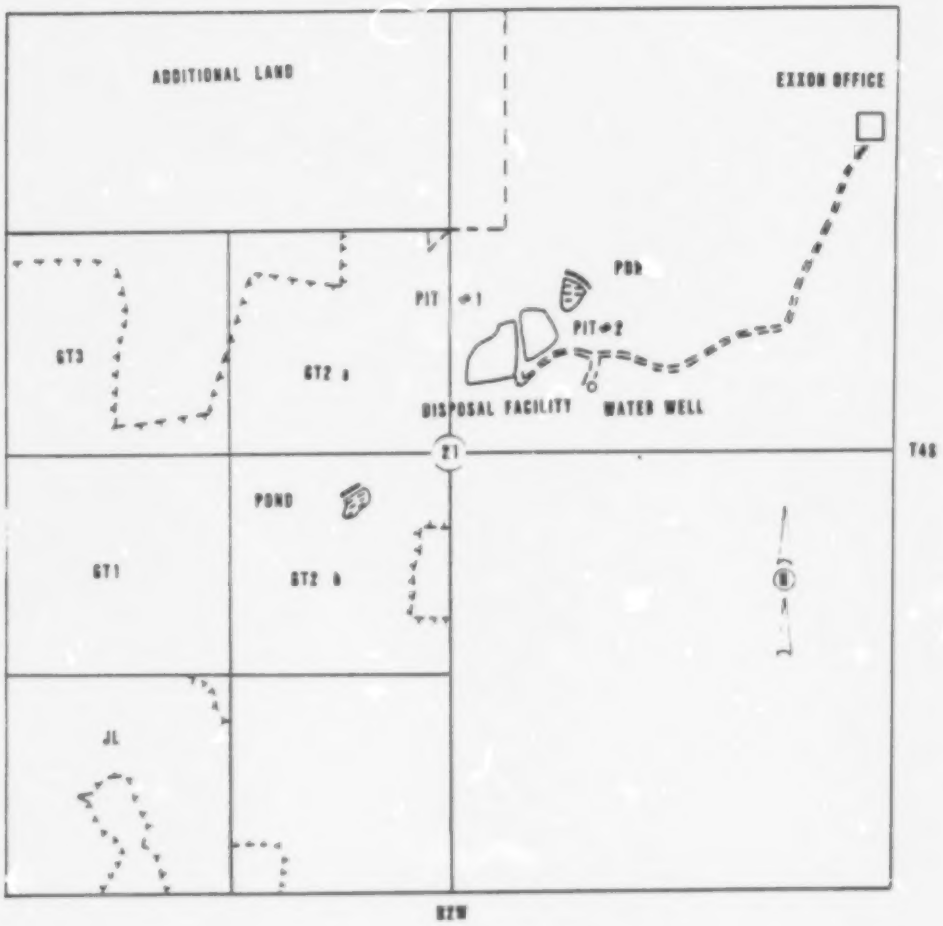

Fig.1. Project location showing the mud pits and various receiving soil units in Carter County, Oklahoma.

TABLE 1

Environmental and operational constraints
on commercial and non-commercial soil farming in Oklahoma

Environmental Constraints	Operational Constraints
1. No soil type having a slope greater than 5 % be used.	1. Sufficient amount of surity to reclaim the land if damaged.
2. No soil where the depth to bedrock is less than 20" be used.	2. Install monitoring wells at appropriate locations and sample every six months.
3. No land which lacks atleast 12" of heavy textural soil in its profile be used for soil-farming.	3. Weather Restrictions: a. no soil farming during or when the rain is imminent. b. no soil-farming when soil moisture is high. c. when the ground is frozen. d. during gusty winds.
4. Soils which are flooded at 2-yr frequency are not eligible.	
5. Soils where salinity status is more than 4000 micromhos should not be used.	
6. Soils having an ESP > 15 should not be used.	4. Buffer Zones: a. no soil-farming within 100' of a property line. b. within 50' of any stream.
7. Areas with shallow water table are not eligible.	
8. Soil tract not within 100 feet of Water Quality Stream, pond, lake or wetland.	c. within 300' of domestic well. d. within 1300' of a municipal well.

TABLE 2
Chemical composition of the mud in Pit # 1 and Pit # 2

Parameter	Concentration	
	Pit # 1	Pit # 2
EC (micromhos)	22,000	14,000
T D S (ppm)	13,500	9,000
Chloride (ppm)	5,675	4,050
% Dry Wt.	38.10	13.04
Oil & Grease (ppm)	1,000	3,000

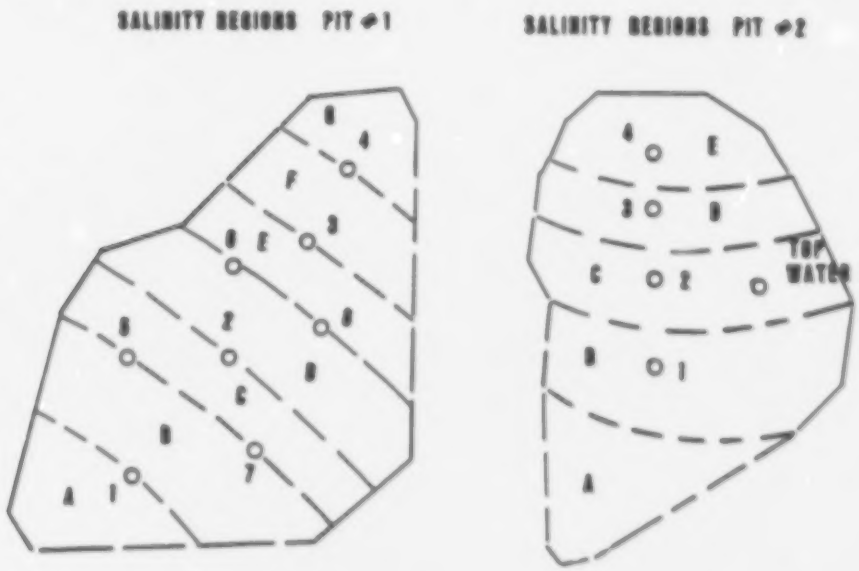

Fig. 2. Sampling locations and determination of "salinity regions" in pit # 1 & pit # 2.

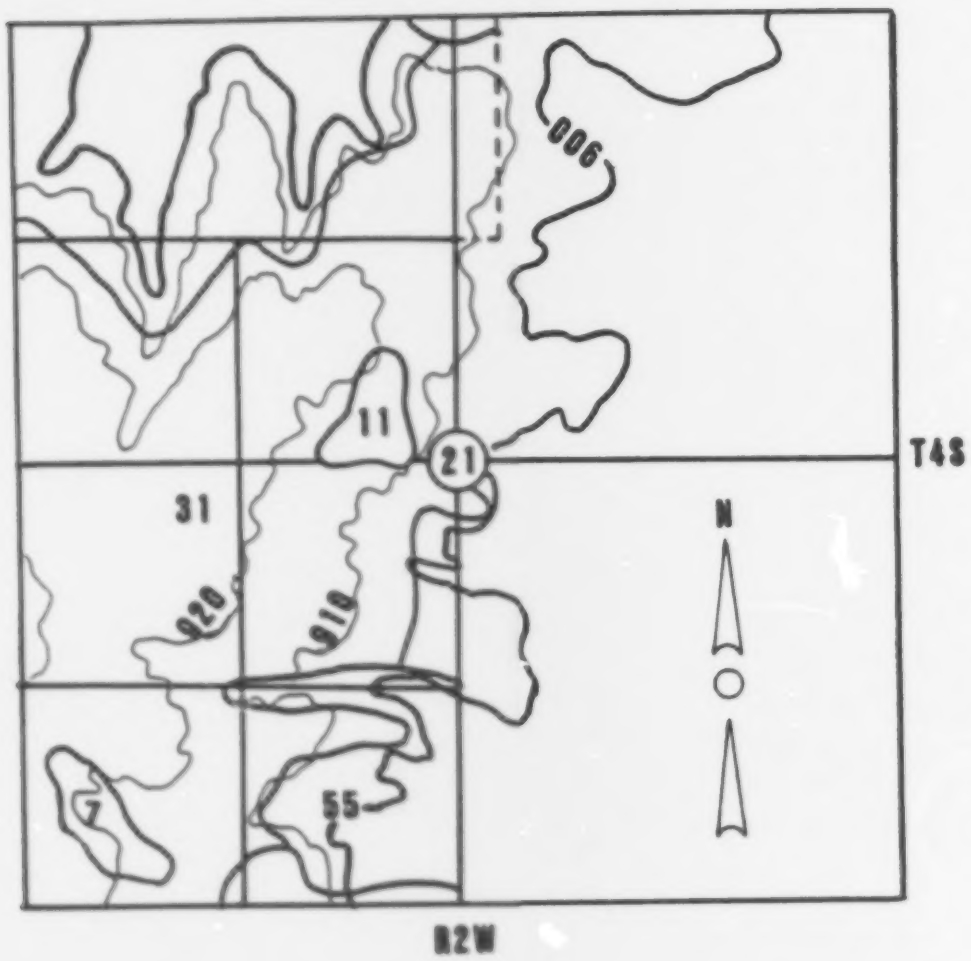

Fig. 3. Soil type distribution (series # 31 & # 11) and the topography around project location.

TABLE 3

Summary of the post-application salinity status at various sampling locations

Sample #	pH	T D S	Cl	Cl/TDS
1	7.53	1408	466	0.33
2	7.51	1280	443	0.34
3	7.08	1216	408	0.33
4	7.52	1024	372	0.36
5	7.51	1152	408	0.35
6	7.55	1088	230	0.21
7	8.06	1472	479	0.32
8	8.02	2304	798	0.34
9	7.52	1600	479	0.29
10	7.53	1216	337	0.28
11	8.03	2176	763	0.35
12	8.02	1472	461	0.31
13	7.52	1344	426	0.31
14	7.52	1728	585	0.31
15	8.03	1600	550	0.34
16 *	8.02	1760	621	0.35
17	7.50	1984	532	0.26
18	7.52	1600	510	0.31
19 *	8.03	2112	710	0.33
20 *	8.00	1792	532	0.30
21	7.58	1792	568	0.31
22	7.82	1344	459	0.34
23	7.72	1664	550	0.33
24	8.02	2176	763	0.35
25	8.00	1792	550	0.31
26	7.50	1664	408	0.24
27	8.02	1792	603	0.33
28	7.81	1472	400	0.27
29 *	7.56	1696	532	0.31
30	8.03	2336	798	0.34
31	8.00	1664	497	0.29

* Areas where accidental spills were observed

LANDFARMING OIL BASED DRILL CUTTINGS

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1. Abstract

Over the last three years Amoco Canada has been developing a technique to successfully landfarm oil based drill cuttings. Oil based drill cuttings are often referred to as DIMR, a residue of diesel invert mud and rock cuttings. This method is based on the following principles:

-- Modifications to the drilling mud solid control system such that the amount of oil retained in the cuttings is substantially reduced.

-- Minimizing the oil to soil ratio by evenly spreading the cuttings over a suitable land area.

-- Utilizing the soil's natural capacity to biodegrade hydrocarbons, and enhancing this capacity through the application of chemical fertilizers and mechanical cultivation.

Thirty-two wellsites in the Grey Wooded soil zone of Alberta, drilled with invert mud, have been treated by landfarming and show positive results. During the 3 years the program has been in place, each landfarming area has been given 1 to 2 treatments per year. Each location has shown a significant reduction in the oil content of the soil, in electrical conductivity (EC), and salt levels and it is anticipated that many will meet or exceed government revegetation standards by the end of this year's growing season (1990). To date, no deleterious effects from leaching or fluid migration have been observed, although monitoring is still ongoing.

This type of treatment procedure is low cost, even considering sampling, analysis, treatments, and the 2 to 4 years required to reclaim the site. It is hoped that this timeframe could be reduced as more data becomes available and the technique is "fine tuned".

...2.../

While this approach has apparently been successful in the soil zone mentioned, it could be limited by the availability of biologically active soil horizons, the surface area to cutting volume ratio, and the oil to cuttings ratio.

Further evaluation is still required to determine the limits of this reclamation method. However, at this point in time, there is every reason to think that this approach will become a primary method of dealing with oil based drill cuttings.

2. Introduction

Over the last 4 years, Amoco Canada has developed a technique to successfully landfarm oil based drill cuttings. This is a method of disposing of the Drilling Invert Mud Residue (DIMR) by utilizing the native soil micro-organisms to degrade the oil phase of the invert fluid, and the naturally occuring dilution and leaching action to reduce the high chloride levels in the water phase. An outline of this landfarming process and an evaluation of the analytical data is contained in this paper.

3. Site Description

The landfarming sites almost all occur on crown lands in the Grey Wooded soil zone (luvisol) of west central Alberta. This soil zone is typified by a shallow weathered topsoil horizon, overlying a mostly clay subsoil with occasional seams of sand and gravel. Landforms are glacial in origin, with the topography being gently to severely rolling. Forest cover type ranges from typical aspen woodland to boreal species (pine, spruce, poplar).

Mean annual precipitation levels are approximately 550 mm, most of this generally occurring during the spring break-up period and early summer months.

There are 32 individual landfarm sites; 21 of which are clustered in the "Ricinus" field, 8 in the "Brazeau" field, and 4 other scattered deep hole exploration wells. DIMR volumes range from approximately 200 - 300 m^3 per location in the Ricinus field, 300 - 400 m^3 in the Brazeau field, and 450 - 700 m^3 in the 4 other locations.

Most of these wells are in production and average approximately 1.65 ha in area, of which roughly 1/3 - 1/2 of the wellsite is available for the landfarming operation.

...3.../

This means that the average ratio of cuttings to surface area is roughly 450 m^3/ha, or a layer of cuttings 4.5 cm deep, although this various somewhat from site to site.

4. Invert Mud System

Amoco's standard invert diesel mud system is based on a 1 to 4 water in oil emulsion. The oil component is #2 diesel fuel, while the water phase is a $CaCl_2$ brine with chloride ion levels in the order of 200,000 mg/l. The fluid will also contain emulsifiers and wetting agents (surfactants), and may contain lime and other additives in small quantities.

5. Landfarm Operations

The invert landfarming operation consists of several steps:

1. Invert fluid and water that has drained from the cuttings pile is first treated and/or removed for off lease disposal. The cutting pile is dyked, so this fluid phase tends to be mostly rain water. A conventional activated carbon/flocculent treatment is generally used.

2. The oil contaminated cuttings are then spread as thinly as possible with a dozer over the designated landfarm area. A general guideline is to try and keep the layer of cuttings less than 5 cm thick, although this is not always possible, as wet cuttings can be difficult to spread uniformly, and the surface area available is sometimes limited.

3. The previously stockpiled surface strippings (topsoil and humus layer) are then dozed over and mixed in with the cuttings. The area is cultivated with a set of discs, or a tractor mounted rototiller. At this time, high nitrogen fertilizer is broadcast and mixed into the cuttings topsoil/layer. If a soil conditioner or bacterial culture such as manure is to be added, it would also be introduced and spread at this time.

The three objectives of this operation are to maximize the surface contact between the cuttings and soil bacteria, aerate the soil/cutting mix to promote aerobic decomposition, and boost the soil microbe count by providing additional limiting nutrients in the form of high N_2 fertilizer. These are the same general principles that are applied when treating small oil spills, or composting in your back yard, and are consistent with the findings of Scroggins, et al (1988).

The cultivate/fertilize cycle is then repeated as often as required, generally twice a year for 2 or 3 years. The type of fertilizer, and

...4.../

recommended application rate is determined by a regular soil sampling and analysis program. The two most frequently used are 34-0-0 and 11-51-0. Rates vary a great deal, but have generally been in the order of 1000 kg/ha.

Once analytical results demonstrate the oil to soil ratio has dropped to the 1-2% range, the site is given a final treatment and a suitable grass seed mixture is sown. The most common one is Creeping Red Fescue - 40%; White Dutch Clover - 12%; Climax Timothy - 24%; Canada Blue Grass - 24%.

6. Mud Solids Control

Continuing the work begun by Braun and Molner (1988), Amoco Canada's Drilling Dept. has placed a renewed emphasis on "closed loop" drilling. This has resulted in a substantial reduction in the amount of invert fluid being dumped with the drill cuttings.

Initial modifications to the mud system involved:

-- increasing mesh screen size in the shale shakers
-- substituting 2 or more centrifuge units for the desander desilter
-- continuously agitating the shaker tank

Other modifications and in situ treatment systems are being evaluated, but that subject is beyond the scope of this paper. These efforts have been paying real dividends during the clean-up and landfarming operations, as the reduction in total invert fluid volumes left on site is a key factor in reducing bioremediation time.

At present, our timeframe to completely finalize a site is 2 to 4 years. Improved solids control at the rig should cut the recovery time by as much as half, which reduces costs and minimize any negative potential impacts of invert landfarming.

7. Soil Sampling

Soil sampling was initiated in 1986 at several sites in the Brazeau area, and is currently conducted at 32 sites in the Brazeau and Ricinus areas on an annual basis.

Landfarming sites are divided into 2 to 4 sections for composite soil sampling, and a minimum of 15 soil cores are taken in each section to make a composite sample. The intent is to sample soil at similar locations each year.

...5.../

The depths of soil sampling are 0-15 cm and 15-30 cm, with a few sites being sampled at 30-45 cm. A composite soil sample is obtained for each depth and each section of the landfarmed area. A control sample is also taken for comparison with soils being analyzed from the landfarm area.

Composite soil sampling from each section is important since it is difficult to evenly spread the spent invert mud residues and cuttings by mechanical means. The concentration of total hydrocarbons or soluble salts will vary on the site due to the limitations of mechanical spreading. By dividing a site into 2 to 4 sections, treatment can be specifically directed to each section.

8. Soil Analysis Parameters

Each soil sample is analyzed for the following parameters: pH, total hydrocarbons (% HC), electrical conductivity (EC), % saturation, sodium absorption ratio (SAR), calcium (Ca), magnesium (Mg), sodium (Na), sulphates (SO_4), chlorides (Cl), theoretical gypsum requirement (TGR), nitrogen (N), phosphorous (P), and potassium (K). From these analyses, fertilizer recommendations are determined. At present, government guidelines or regulations do not specify the parameters for the soil analysis.

9. Trends

The pH of the soil has consistently been in the range of 6.4 to 7.4. For most of the landfarming sites the pH of the soil has been very close to 7. At a few sites, the soil pH has ranged from 5.1 to 5.7 due to the soil type and characteristics of the area.

Before modifications were initiated at the drilling rig, and the appropriate spreading depth of DIMR was determined, the percent of total hydrocarbons in the soil in the first year was much greater than 1%. An example is Amoco Brazeau 10-28-45-14-W5M as shown in Table 1. The percent total hydrocarbons in the 0-15 cm depth has decreased from 7.37% in 1987, to 1.45% in 1988, to 1.28% in 1989, and 0.58% in 1990. Fertilizer applied twice a year in 1987 and 1988, and extensive cultivation accounts for this rapid decrease in hydrocarbons.

Several landfarming sites, such as Amoco Ricinus 5-34-32-7-W5M and Amoco Ricinus 10-02-34-8-W5M as shown in Table 2, had total hydrocarbons of 1.97% & 3.29% respectively, in the 0-15 cm depth in the first year. After 3 fertilizer treatments and cultivation, the percent hydrocarbon dropped dramatically to approximately 0.14% and 0.39% respectively. This rapid decrease in the hydrocarbon content is due primarily to the

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addition of nitrate fertilizers which assist in increasing soil bacteria.

Many landfarming sites have a percent total hydrocarbons content of less than 1% in the first year. Table 3 for Amoco Ricinus 14-34-32-7-W5M shows a total hydrocarbon content in the 0-15 cm depth of 0.72% in 1988 and 0.2% in 1989, and 0.13% in 1990. Amoco Ricinus 10-28-34-8-W5M shows a similar decreasein hydrocarbons. The oil content on the shale cuttings has been greatly reduced by the use of centrifuges and modifications to the shale shaker screens. This has resulted in an initial lower concentration of oil.

The soil analysis for the 32 sites show that hydrocarbons are not migrating or leaching. Initially, the hydrocarbon content in the 0-15 cm and 15-30 cm depths may be similar, depending upon the depth of cultivation. However, the maximum hydrocarbons content is normally found in the shallower depth of 0-15 cm. The hydrocarbon content does not appear to increase in the 15-30 cm or 30-45 cm depth with time. Other studies (Ashworth, Scroggins, McCoy, 1988) have also indicated that hydrocarbons are not migrating or leaching.

There is a wide range of electrical conductivity for the sites, with some initial values reaching 66.7 mS/cm. Table 4 shows the range for the landfarming sites at wellsites Brazeau 10-28-45-14-W5M, Ricinus 5-34-32-7-W5M, and Ricinus 10-28-34-8-W5M. Calcium Chloride ($CaCl_2$) and other soluble salts are the factors contributing to the wide range of electrical conductivity. The trend has been for the electrical conductivity to decrease rapidly in both the 0-15 and 15-30 cm depths. For many sites, the EC is well below 5 mS/cm in the second or third year and very similar to the control soil samples.

Chloride levels as shown in Table 5 show a wide range in values for the first year of landfarming. Chloride levels in the first year may vary from several hundred to several thousand PPM. Due to leaching and an abundance of rain in 1988, 1989 and 1990, chloride concentrations have dropped significantly each year.

Overall sodium concentrations have not been a problem. However, where sodium levels have been excessive in comparison to the control site, gypsum has been added to alleviate the problem.

With respect to calcium (Ca), magnesium (Mg) and sulphates (SO_4-S), there have been elevated levels in comparison to the control sites. However, no major problems with respect to landfarming have been encountered. For five landfarming sites, a complete soil analysis is given in Table 6. Amoco is presently in the process of setting up ground water monitoring wells at four sites to determine movement of leachates.

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10. Time for Reclamation

The percent total hydrocarbon tends to be the limiting factor for the reclamation. Sites with a higher hydrocarbon content, 3%-7%, may take 2 - 4 years for reclamation. Many sites with a percent hydrocarbon content of 0.5 - 2% initially, have been successfully revegetated in the second growing season. Overall, once the hydrcarbon content in the soil is 1% or less and chlorides are less than 1000 ppm, the site can be revegetated successfully.

Fertilizer is added at least once per year with some sites receiving two fertilizer applications per year. The addition of fertilizer containing nitrates and phosphorous has been a successful strategy. Manure may be added to landfarming sites and previous field studies (J. Ashworth, 1989) indicate this would be beneficial. The addition of straw in areas of very little topsoil has merit, especially where the topsoil is poor. The addition of sewage lagoon material is being assessed to see if this would expedite the reclamation process. The objective would be to increase the bacterial numbers to enhance hydrocarbon breakdown.

11. Costs

Thus far, the landfarming operation as outlined has proven to be a very cost efficient method of handling invert cuttings. The average landfarming costs, above and beyond our normal site clean-up costs, are approximately $8,000/location. This includes the landfarming operation, soil sampling program and lab analysis.

This compares very favourably with other disposal options currently being tried in Alberta. Based on field trials recently conducted with fixation and incineration, it is estimated that costs for these methods would be $40,000 and $60,000 respectively.

12. Limitations

Government regulatory bodies in Alberta to date, have given the industry a somewhat cautious green light for this disposal procedure. We have yet to see any serious problems or shortcomings, and at this point in time, it appears to be a satisfactory method of handling invert cuttings. However, there are limitations:

As mentioned previously, the oil/soil ratio must be around 1% by weight in order to establish a satisfactory vegetative cover. Therefore, if we:

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-- are restricted by the area available to spread the cuttings
-- have to handle large volumes of cuttings
-- have a high ratio of oil to cuttings

(or some combination of these), we may end up with a site that will take a very long time to reclaim.

VOCs (Volatile Organic Compounds) may evaporate from the farmed cuttings but have not been of great concern since most landfarm sites are not close to any residences. Furthermore, only trace amounts of VOCs may be involved.

Salt loading of the soil from the brine phase of the DIMR does not appear to be a problem. Regulations stipulate that no fluids with a chloride concentration above 1000 ppm may be disposed of off site. We comply with this by conducting our landfarming operation on the well-site. However, the fact is that soil analysis indicates that the $CaCl_2$ quickly leaches out. We have yet to detect any observable necrotic effects on either the surrounding forest or the new grass crop that would suggest salt damage.

Possible ground water contamination is a concern, although again there have been no obvious indications that this is having a significant impact. This aspect of our operation shall be further investigated through a ground water monitoring program to be undertaken in the near future.

Lack of topsoil or humus material to mix with the DIMR can of course be a very limiting factor. Extra effort made during wellsite construction to conseve organics is more than made up for during the landfarming operations. Trucking in and spreading a soil conditioner such as manure is an expensive option.

13. Advantages

Aside from the low costs, the primary advantage to landfarming is that a natural process, with minimum energy input, is being utilized to dispose of a waste substance. The waste is not simply covered up or stored, as occurs at a landfill. Landfarming of DIMR does not cause air emission problems in comparison to incineration where smoke and particulates may be of concern. Basically, landfarming of DIMR handles the waste on-site and transport of the material is not required.

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14. Conclusion

To date, Amoco's landfarming of oil based drill cuttings has been showing positive results. Reduction of invert residue on the cuttings through improved solids control while drilling, is felt to be a key factor in expediting the process. There have been no noticeable environmental impacts, but studies are ongoing to try and determine the implications of leaching. The revegetation of many sites shows that landfarming is an acceptable disposal option for oil based drill cuttings.

15. Acknowledgements

The authors would like to acknowledge Mr. Ed Lambert of Alpine Environmental Ltd., who has played a major role in developing Amoco's landfarming procedure.

16. References

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TABLE 1

Percent Total Hydrocarbons in 0-15 cm and 15-30 cm depths.

Amoco Brazeau 10-28-45-14-W5M

YEAR	PERCENT TOTAL HC AT 0-15 CM	PERCENT TOTAL HC AT 15-30 CM
1987	7.37	5.95
1988	1.45	----
1989	1.39	1.17
1990	0.58	0.69

TABLE 2

Percent Total Hydrocarbons in 0-15 cm and 15-30 cm depths.

Amoco Ricinus 5-34-32-7-W5M

YEAR	PERCENT HC 0 - 15 CM	PERCENT HC 15 - 30 CM
1988	1.97	2.36
1989	0.10*	0.10*
1990	0.14	0.19

Amoco Ricinus 10-2-34-8-W5M

YEAR	PERCENT HC 0 - 15 CM	PERCENT HC 15 - 30 CM
1988	3.29	1.15
1989	0.40	0.10
1990	0.39	0.30

NOTE: * Questionable laboratory analyses in 1989.

TABLE 3

Percent Total Hydrocarbons in 0 - 15 cm and 15 - 30 cm depths.

Amoco Ricinus 14-34-32-7-W5M

YEAR	PERCENT HC 0 - 15 CM	PERCENT HC 15 - 30 CM
1988	0.72	0.80
1989	0.20	0.10
1990	0.13	0.13

Amoco Ricinus 10-28-34-8-W5M

YEAR	PERCENT HC 0 - 15 CM	PERCENT HC 15 - 30 CM
1988	2.04	0.86
1989	0.10	0.10
1990	0.15	0.13

TABLE 4

Electrical Conductivity (mS/cm)

		0 - 15 CM	15 - 30 CM
Brazeau 10-28-45-14-W5M			
	1987	66.7	63.8
	1988	11.4	----
	1989	2.5	2.1
	1990	1.9	1.6
Ricinus 5-34-32-7-W5M			
	1988	12.2	16.2
	1989	1.0	0.8
	1990	0.5	0.6
Ricinus 10-28-34-8-W5M			
	1988	----	5.1
	1989	1.2	1.3
	1990	0.6	0.8

TABLE 5

Chloride (PPM)

		0 - 15 CM	15 - 30 CM
Brazeau 10-28-45-14-W5M			
	1987	8256	8550
	1988	2140	----
	1989	117	76
	1990	86	48
Ricinus 5-34-32-7-W5M			
	1988	2234	2653
	1989	131	58
	1990	40	41
Ricinus 10-28-34-8-W5M			
	1988	----	741
	1989	210	250
	1990	21	61

TABLE 6

DETAILED SOIL ANALYSIS REPORTS FOR FIVE SELECTED SITES

Location (Lsd)	Date	Depth (CM)	THC %	PH	E-C mS/cm	SAT %	SAR	CA ppm	MG ppm	NA ppm	SO_4-S ppm	CL ppm	TGR t/ac	N ppm	P ppm	K ppm	S ppm
Brazeau 10-28-45-14-W5	1987	0-15	7.37	10.0	66.7	36	11.6	4745	35	1747	184	8256	90.8	---	---	---	---
		15-30	5.95	9.8	63.8	36	11.1	4658	17	1656	153	8550	81.6	---	---	---	---
	1988	0-15	1.45	7.0	11.4	---	4.1	966	82	367	---	2140	---	---	---	---	---
		15-30	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
	1989	0-15	1.39	7.1	2.5	49	1.4	201	28	56	129	117	<0.1	---	---	---	---
		15-30	1.17	7.2	2.1	47	1.4	168	22	49	114	76	<0.1	---	---	---	---
	1990	0-15	0.58	7.4	1.9	50	1.5	150	20	45	119	86	<0.1	1	7	141	---
		15-30	0.69	7.4	1.6	48	1.0	127	18	47	107	48	< .1	1	3	141	---
Ricinus 5-34-32-7-W5	1988	0-15	1.97	7.2	12.2	52	2.5	939	136	222	31	2234	<0.1	1	6	224	---
		15-30	2.36	7.5	16.2	47	3.0	1194	136	282	35	2653	<0.1	1	3	206	---
	1989	0-15	0.10	6.7	1.0	65	0.9	155	28	47	96	131	< .1	5	2	244	27
		15-30	0.10	6.7	0.8	57	0.6	110	22	26	37	58	< .1	15	1	242	14
	1990	0-15	0.14	7.2	0.5	55	0.4	32	10	7	5	40	1.2	1	14	252	---
		15-30	0.19	7.3	0.6	52	0.8	25	36	18	7	41	1.6	1	3	260	---
Ricinus 14-34-32-7-W5	1988	0-15	0.72	6.6	7.6	85	1.0	409	74	77	11	977	<0.1	---	104	161	---
		15-30	0.80	6.7	5.2	77	1.2	495	110	98	9	1230	< .1	---	59	184	---
	1989	0-15	0.20	6.5	1.1	75	0.5	172	40	28	74	220	0	31	6	277	19
		15-30	0.10	6.5	2.2	73	0.9	272	74	65	95	260	0	20	1	250	16
	1990	0-15	0.13	7.3	0.8	66	0.5	19	18	10	6	97	< .1	2	4	333	---
		15-30	0.13	7.3	1.1	64	0.8	13	24	18	5	215	< .1	2	4	326	---
Ricinus 10-2-34-8-W5	1988	0-15	3.29	7.1	20.3	40	5.3	1160	131	449	7	3337	< .1	1	6	147	---
		15-30	1.15	7.3	10.5	38	3.5	533	75	200	3	1403	< .1	1	3	88	---
	1989	0-15	0.40	6.7	1.1	66	1.6	168	31	84	83	170	0	1	6	135	15
		15-30	0.10	6.7	1.5	67	1.6	186	---	81	38	300	0	3	1	233	13
	1990	0-15	0.39	7.5	0.7	55	0.9	60	10	21	12	30	0	1	6	130	---
		15-30	0.30	7.5	0.9	53	1.5	55	10	34	5	98	1.1	1	2	130	---
Ricinus 10-28-34-8-W5	1988	0-15	2.04	7.1	10.2	47	1.9	727	71	137	35	1702	< .1	1	22	151	---
		15-30	0.86	7.0	5.1	49	4.1	314	42	204	23	741	< .1	4	9	156	---
	1989	0-15	0.10	6.6	1.2	65	1.4	164	24	70	107	210	0	7	1	170	20
		15-30	0.10	6.6	1.3	62	1.6	146	26	82	102	250	0	15	0	194	160
	1990	0-15	0.15	6.9	0.6	51	0.6	48	9	14	10	21	1	1	19	160	---
		15-30	0.13	7.2	0.8	53	1.0	58	11	22	17	61	3	2	4	155	---

FOOTNOTE: Soil analysis completed from all 32 sites, but results included for only 5 sites.

MANAGEMENT OF AMINE PROCESS SLUDGES

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Introduction

The petroleum industry in Alberta produces over 37 million m^3 of oil and gas wastes which are presently disposed of in landfills, deep wells, ponds and at the hazardous waste treatment facility at Swan Hills (1). Since 1985, the Canadian Petroleum Association (CPA), in conjunction with Environment Canada, has been assessing these wastes and evaluating environmentally acceptable methods for their treatment and disposal.

Amine sludges, wastes from the process used to remove sulphur from sour gas (gas containing H_2S), have been ranked as high with respect to their potential for environmental concern (2). Some amine sludges contain compounds that are carcinogenic, toxic or corrosive. Disposal of these wastes has become a problem because their classification was not clear. The acceptability of landfilling these wastes is being questioned by landfill and sour gas plant operators.

The management of these wastes must take into consideration their composition and hazardous nature, ways of reducing any hazard they pose and the volume produced, their recycling potential and the technical, environmental and economical feasibility of disposal methods. Most amine wastes are produced from processes using either diethanolamine (DEA) or monoethanolamine (MEA) as scavenger/solvents. This paper focuses on these two types of waste, examining the management options available and providing an evaluation of those options. The details are summarized in a report prepared for the CPA and Environment Canada (3).

Purpose

The purpose of this project was to determine and evaluate the options available for managing sour gas processing plant DEA and MEA sludges, to recommend management options that are environmentally acceptable to government and the industry and to identify further research requirements to fully assess the recommended options.

Characterization of the Wastes

Amine compounds such as DEA and MEA are used to remove the sulphur from sour gas under pressure. The sulphur is then stripped out of the amine compound at high temperatures and both amine and sulphur are recovered. The amine is then recycled. Sodium hydroxide is often added to the amine to prevent corrosion (4).

During the process, the amine compounds are attacked by CO_2 and break down, forming degradation products. A number of factors affect this process, including temperature, pressure, gas composition and pH (5). At least 17 amine degradation compounds have been found in amine solutions (5) and one, N-(hydroxyethyl)ethylenimine (HEM or aziridinethanol), is considered to be toxic. HEM is also classified as a positive animal carcinogen as is triethanolamine (TEA) while

oxizolidone (OX) is a suggestive animal carcinogen. Other compounds such as carboxylic acid, thiosulfuric acid and thiocyanic acid, sodium chloride, iron sulphide and sodium hydroxide have also been found in the amine solution (8). DEA solutions are filtered to remove some of the degradation compounds while MEA solutions are reclaimed; both systems produce a waste sludge.

The filters used in the DEA process include diatomaceous earth and cellulose fibre-diatomaceous earth. The filters are backwashed periodically and the backwash liquids are often discarded into a pond, then deep well injected (9). The filters are changed when the process indicates that degradation products or particles are accumulating. There was little information available on the backwash liquids but they may contain similar compounds at lower concentrations. Monenco Consultants Ltd. (10) report that 5 - 30 m^3 are produced annually by each gas plant while two plant operators estimate their volume of solid amine wastes to be 3 and 11 tonnes per year respectively (11, 12).

The MEA sludges are liquids of varying viscosity which are diluted with water, if necessary, allowed to settle, then deep well injected. Monenco Consultants Ltd. (13) reported the volume of this waste to be less than 5 m^3/year per plant but plant operators provided estimates of 55 and 71 tonnes of liquid MEA waste produced per year (14, 15).

In this study, an analysis of amine sludges from four Alberta gas plants (two DEA filter sludges and two MEA reclaimer bottoms) determined that three had a high pH and contained high concentrations of nitrogen and sodium but levels of other elements were at or below Canadian background soil levels (Tables 1, 2). These results agree with characterizations of amine leaf filter sludges and reclaimer bottoms by Monenco Consultants Ltd. (16). One DEA filter sludge (Plant B) contained only low levels of sodium and nitrogen but had concentrations of nickel and copper above the levels found in Canadian soils (17). Sodium hydroxide was not added to the amine solution during the gas treating process and the pH of the amine sludge was low (pH=4.5) so corrosion of metals may have been occurring.

Analysis of the four amine sludges by GC/MS indicated that they contain a variety of amine compounds, including a number of unknown and unidentified compounds (Tables 3, 4). Of those compounds known to be carcinogenic or toxic, TEA was detected in the Plant B DEA filter sludge. Other analysis of amine sludges found similar compounds (18, 19) although OX was found in reclaimer bottoms from a vacuum reclamation of the Plant A amine solution (20).

In testing for hydrocarbon compounds in amine filter sludges and reclaimer bottoms, Monenco Consultants Ltd. (21) found a number of compounds such as phenols and benzenes, but all at levels less than 9 ppm (Table 5). Formic acid, acetic acid, proprionic acid and oxalates were found in high concentrations in other sludges (22).

The toxicity of the four study sludges to bacteria, germinating seeds and fish was also tested. All sludges were found to be toxic to the organisms tested except for the Plant B DEA sludge which was not toxic to germinating seeds at a concentration of 20%. Other tests of amine filter sludges and reclaimer bottoms have found them to be toxic to seeds, algae, fish, cladoceran, nematodes and bacteria (23). The S.O.S. Chromotest was also used to detect the presence of genotoxic agents which cause damage to DNA of cells. Neither the amine filter sludge nor the reclaimer bottoms were genotoxic at concentrations below their level of toxicity to the test organism (24). However, the toxicity of the two wastes was extreme, and their genotoxicity could not be adequately tested.

In Alberta, the Hazardous Waste Regulations (Alta. Reg. 505/87) specify substances that are classified as hazardous. Of the compounds found in the sludges, MEA, acetic acid, formic acid, proprionic acid and oxalates are classified as hazardous due to their corrosive nature. Benzene, ethyl benzene and phenol are also listed as miscellaneous hazardous materials and phenol is also considered to be toxic. However, the pH of the sludges would not result in their classification as corrosive. There is no information available to consider the toxic nature of the wastes themselves

since that classification is based on toxicity to rats and the toxicity of the amine sludges to rats has not been assessed.

The unknown nature of many of the compounds found in the wastes and the known carcinogenicity of some of the compounds indicate that caution is required in classifying these wastes. In addition, the composition of these amine sludges varies from plant to plant and from time to time within one plant. They should be considered as hazardous with respect to both handling and disposal until there is further evidence as to their nature. Otherwise, if future testing of these sludges results in a hazardous classification, the producer may be liable for compensation for any negative health effects and cleanup costs.

The metal content of these wastes is low enough that reclamation of the metals is not a feasible option. Reclaimer bottoms analyzed by Monenco Consultants Ltd. (25) contained 80% MEA, enough to warrant further reclamation of MEA but analysis of other MEA sludges indicated that most recovery processes were extremely efficient, with the wastes containing 0 to 8% MEA. DEA was also low in the analyzed sludges.

Treatments that will break down the hazardous compounds in the sludges will be required. Both sodium and nitrogen may also pose a problem in disposing of these wastes since sodium will cause salinization of soil and high concentrations of nitrates in ground or surface water are toxic, especially to infants (26).

Biodegradation

A number of studies have assessed the biodegradation of specific compounds found in amine sludges, such as DEA, TEA and MEA (27, 28, 29). No toxic intermediates were reported when an isolated sewage bacteria was used to anaerobically degrade these compounds into substances useable by the microorganisms (30). Other aliphatic amines have been successfully treated by an activated sludge process (31). Organic compounds such as phenols, benzenes, aliphatic acid, formic acid and acetic acid also found in the sludges are also readily biodegraded by bacteria (32, 33, 34).

The biodegradation of the four amine sludges when mixed with soil and incubated for six weeks was assessed in this study using changes in toxicity as a measure (Table 6). The toxicity of two MEA reclaimer bottoms to fish decreased and toxicity to bacteria did decrease for Plant D although the results for Plant C were not significant. The Plant A DEA filter sludge produced toxicity results that were inconclusive while the Plant B DEA cellulose fibre filter sludge showed no significant change in toxicity to fish but did decrease in toxicity to bacteria.

This study (35) also determined that perennial rye actually grew better in low concentrations of three of the four sludges than in the control soil. The plants appeared to be using nitrogen from the degrading amine compounds as a nutrient. Only the Plant B DEA cellulose fibre filter sludge inhibited plant growth at the lowest concentration tested, possibly due to either the release of adsorbed toxic compounds by the degrading fibre or competition between the plants and bacteria degrading the fibre. In general, the results suggested that there was biodegradation of the two MEA sludges and the Plant A DEA diatomaceous earth filter sludge when the sludges were mixed with soil. These results also indicated that soil immobilized compounds in all sludges that were toxic to seeds and to fish. The assimulative capacity of the soil ranged from 0.5% to 2.5% (10-50 t/ha).

Options for Treatment and Disposal

There are five options that must be considered for disposal of these wastes; landfilling, land treating, deep well disposal, surface water discharge and incineration.

Landfilling

Under Alberta regulations, solid hazardous wastes could be landfilled at any Class II landfill which must have a synthetic or clay liner, surface run-on and run-off control systems, a gas interception and venting system and a ground water monitoring system (36). Liquid hazardous wastes would not be acceptable at such a site and it is not recommended that such wastes be landfilled due to problems with leaching and contamination of surface and ground water (37). The classification of MEA and DEA wastes as hazardous is still under question because they may contain some compounds listed as hazardous and the toxicity of the wastes to rats or their effect upon the environment has not been determined (38).

The solid DEA filter sludges, once they have been drained to ensure they contain no liquids, could be landfilled at a Class II landfill. The MEA reclaimer bottoms could be solidified, using a bulking agent such as Portland cement, then landfilled at a Class II site. This would increase the volume of waste for disposal.

Landfilling is becoming an unpopular option for waste materials if other environmentally acceptable disposal methods are available. Landfilling only stores the waste - it neither renders the waste harmless nor does it permanently immobilize the waste (39). In addition, landfilling fees are increasing to cover construction and decommissioning costs of the landfill. Landfill operators are also becoming reluctant to accept industrial wastes such as amine sludges which may be hazardous or classified as hazardous at some time in the future (40).

Land Treatment

Land treatment is the controlled application of a biodegradable waste to soil which allows soil bacteria to break down the waste into harmless components which are used by soil bacteria and plants. Soil also will immobilize some waste compounds, assisting in preventing contamination of ground or surface water (41). The assimulative capacity of the soil depends upon a number of factors, including the toxicity of the waste to bacteria and to plants, the immobilization of the hazardous components of the waste, the rate of biodegradation of the waste compounds and the transformation or detoxification of components by soil microorganisms (42). It is important to ensure that the soil assimulative capacity is not exceeded when applying the waste, either in one application or in repeat applications. Otherwise, damage to soil and soil microorganisms and contamination of surface or ground water may result.

This study indicates that soil does immobilize these wastes, that three of the four are degraded when mixed with soil and that addition of a low concentration of these three wastes results in increased growth in plants. The MEA reclaimer bottoms and Plant A basic DEA diatomaceous earth filter sludges are good candidates for land treatment.

However, the acidic cellulose fibre filter DEA sludge inhibited plant growth and, although toxicity to bacteria decreased, toxicity to fish did not. This sludge also inhibited growth of perennial rye. Treatment such as composting would be required for this sludge before it is applied to soil. In addition, it contained levels of nickel and copper, probably from metal corrosion, that were higher than levels found in natural Canadian soils (43) and which could accumulate to toxic levels if applied repeatedly. Increasing the pH of the amine solution to 7.0 using potassium hydroxide would probably reduce the nickel and copper content of the filter sludge.

Treatments

Amine sludges with high sodium content could cause salinization if applied to land. It would be important to either reduce or eliminate the sodium from the waste prior to land application. Sodium in the liquid waste can be isolated by precipitation, flocculation or other chemical treatments and recovered for reuse, but this treatment would not be useable for the solid DEA filter sludges and it is probably not economically feasible.

In order to eliminate sodium from the wastes, potassium hydroxide could be used to replace sodium hydroxide to maintain the high pH in the process. This compound would be more soluble than sodium hydroxide, resulting in fewer precipitation problems and would be used by bacteria and plants as a nutrient, increasing the rate of degradation. It is possible that a potassium and nitrogen rich amine sludge could be used as a soil amendment for reclamation.

It would also be possible to biodegrade the wastes prior to application, thus reducing concerns regarding overapplication and ground and surface water contamination. For the liquid amine wastes, a bioreactor such as an activated sludge system could be used. However, the wastes would require dilution prior to treatment because they are toxic to bacteria and this would increase water consumption. If other liquid biodegradable wastes could be used to dilute the amine sludges then this would be an acceptable option. Once the wastes are biodegraded, their toxicity should be reduced and they could be applied to land at higher rates. It would still be important to ensure that the assimulative capacity of the soil is not exceeded.

The solid DEA wastes could be composted then applied to land once the organic compounds have broken down. The diatomaceous earth filter sludges would probably require addition of a bulking agent such as straw, sawdust or biodegradable municipal waste.

However, the acidic cellulose fibre filter DEA sludge inhibited plant growth and, although toxicity to bacteria decreased, toxicity to fish did not. This sludge also inhibited growth of perennial rye. Treatment such as composting would be required for this sludge before it is applied to soil. In addition, it contained levels of nickel and copper, probably from metal corrosion, that were higher than levels found in natural Canadian soils (43) and which could accumulate to toxic levels if applied repeatedly. Increasing the pH of this process would probably reduce the nickel and copper content. Addition of potassium hydroxide during the gas treating process to maintain the pH at 7.0 or higher would suffice.

Further research determining the soil assimulative capacity in the field to different types of soil, the potential for repeat applications of the waste and assessing treatments is required.

Deep Well Disposal

Deep well disposal is a disposal method commonly used in Alberta by the petroleum industry and has been used to dispose of liquid amine sludges (44, 45). Deep well disposal involves the injection of liquid wastes into rock formations where the waste material should be contained and isolated from surface and useable ground water. New guidelines are being implemented that will outline the criteria for wastes that may be disposed of in such wells (46). Under these guidelines, wastes that may be treated by conventional physical, chemical or biological means are not acceptable for deep well disposal.

Only the liquid DEA backwash liquids and MEA wastes could be disposed of through deep well disposal. These wastes would require filtering and any solid material would require disposal. However, this study indicates that amine wastes can be treated by conventional means. The metal content of the sludges is generally low, the sodium can be reduced at source or in the waste material and the organic amine wastes are biodegradable into non-toxic components.

Surface Water Discharge

At present, the Gas Processing Plants Waste Water Management Standards in Alberta (47) do not allow liquid process sludges, such as the MEA reclaimer bottoms, to be released into surface water. These standards are being revised and will be made more stringent (48). However, it could be argued that, if the amine sludges were biodegraded, ammonia removed and the resulting waste met the standards, surface water discharge might be an acceptable option.

Such a disposal method would require a bioreactor to digest the sludges prior to discharge. Under the provincial standards, the levels of metals in the sludges, although lower than soil levels, are too high to allow discharge into surface water. The pH and ammonia nitrogen content are both higher than acceptable. There are, at present, no limits on the sodium content of wastewaters for surface water discharge, but the sodium in these sludges could have a detrimental effect upon soils along the stream.

Incineration

Incineration converts wastes to gases and an incombustable solid residue. The product gases are released to the atmosphere and the solid residues, if acceptable, are landfilled. Tailgas scrubbers and electrostatic precipitators are required to ensure that emissions do not exceed guidelines (49). Waste from the scrubber and the residue will also require disposal and, if the waste was hazardous, must be treated as hazardous. Legislation and guidelines regarding incineration, particularly of hazardous waste, are presently being revised and are expected to become more stringent (50).

With the exception of the diatomaceous earth filter, amine wastes are primarily organic. Therefore, they should be easily incinerated, although preheating may be required. However, testing is required to ensure that no toxic gases would form and that scrubbers and precipitators would be adequate. Any ash would also require analysis to ensure that the metal content is below the limits acceptable for landfilling.

At present, only the Special Wastes Treatment Facility in Swan Hills has a licence to incinerate industrial hazardous waste (51). The cost of constructing an incinerator for these wastes would be high and further costs would be incurred with disposal of the solid residues. The diatomaceous earth filter sludges would not greatly reduce in volume if incinerated and could not be incinerated at high temperatures because the filter material would vitrify (52).

Recommended Management Option

Of the five disposal options, land treating is the most acceptable because it offers a means to break down the wastes into their basic components which are then used by bacteria and plants as nutrients. The use of potassium instead of sodium in the process would provide a nutrient, hastening the degradation process. The process producing the cellulose fibre filter sludge should also be maintained at a higher pH to reduce corrosion and the sludge should be composted prior to being applied to land .

Further research determining the soil assimulative capacity in the field to different types of soil, the potential for repeat applications of the waste and assessing treatments is required.

Conclusions

1. Analysis of amine sludges indicates that they usually contain concentrations of metals lower than found naturally in Canadian soils (53). One acidic DEA cellulose fibre sludge did contain levels of copper and nickel above those levels, which may be caused by metal corrosion. The other sludges all had a high pH and high concentrations of sodium and nitrogen. The sodium is usually added to the amine solution during the gas treatment process.

2. Amine sludges contain a variety of amine compounds, some of which have not been identified, and data on the known compounds is limited. Carcinogenic compounds have been found in amine sludges. The results indicate that the composition of the sludges differs between plants and over time at one plant. Low concentrations of organic compounds such as phenols and benzene have also been found in reclamation bottoms and low levels of phenols were found in amine filter sludges (54).

3. The study sludges were found to be toxic to bacteria, fish and, in most cases, to germinating seeds. The acidic, low sodium DEA sludge was not toxic to seeds. Another study has determined that amine filter sludges and reclaimer bottoms were toxic to germinating seeds, bacteria, algae, cladoceran, nematodes and fish (55).

4. It is recommended that the wastes be considered as hazardous for the purposes of handling and disposal to prevent future liability in human health issues and cleanup of spill or disposal sites.

5. This research indicates that the amine compounds in the sludges would be amenable to bacterial degradation. Results from the incubation and plant growth study suggested that degradation of toxic compounds in three of the four sludges had occurred. Results for the fourth, an acidic DEA cellulose fibre filter sludge, indicated no significant change in toxicity to fish, although toxicity to bacteria did decrease. However, addition of 2.5% of this sludge to soil inhibited growth of perennial rye.

6. The recommended management option for these wastes is land treatment following treatment. High sodium contents of the sludges must be reduced and it is recommended that potassium hydroxide be used in place of sodium hydroxide in the process.

7. The process producing the acidic cellulose fibre sludge should be maintained at a higher pH to prevent corrosion and reduce the nickel and copper content of the sludge. This sludge should be composted then land treated. However, further research is needed to assess biodegradation of this sludge.

8. Further research to determine the soil assimulative capacity of amine sludge in the field for different types of soil, the potential for repeat applications of the waste, and to assess treatments is required.

TABLE 1

PARAMETERS OF THE DEA FILTER SLUDGES (ppm unless otherwise stated)

Parameter	Plant A		Plant B	
	Concentration	Range	Concentration	Range
pH	10.6	10.5 - 10.6	4.5	4.5 - 4.6
EC	1.6 mS/cm	1.3 - 1.6	0.22 mS/cm	0.21 - 0.22
Elutrient colour	dark brown		no colour	
	(total concentration)		(total concentration)	
Antimony	<0.005 ppm		<0.005 ppm	
Arsenic	<0.05		<0.05	
Barium	259	217 - 265	277	273 - 284
Beryllium	2	2 - 3	2	1 - 2
Cadmium	2		2	
Chromium	108	105 - 118	90	89 - 90
Cobalt	<0.1		<0.1	
Copper	14	13 - 22	310	280 - 310
Lead	2		<2	
Manganese	62	62 - 66	72	66 - 72
Mercury	<0.005		<0.005	
Molybdenum	<0.2		<0.2	
Nickel	51	49 - 52	180	160 - 180
Nitrogen	16,300	16,300 - 24,800	600	450 - 700
Selenium	<0.3		<0.3	
Silver	<0.5		<0.5	
Tin	2	2 - 7	<2	
Vanadium	84	78 - 86	42	36 - 46
Zinc	44	42 - 45	38	37 - 39
	(soluble concentration)		(soluble concentration)	
Boron	2.38	2.25 - 2.50	0.50	0.38 - 0.50
Calcium	3	2 - 4	3	2 - 5
Magnesium	<1		<1	
Potassium	10		3	2 - 3
Sodium	2,770	2,600 - 2,780	118	118 - 119

TABLE 2

PARAMETERS OF THE MEA RECLAIMER BOTTOM SLUDGES (ppm unless otherwise stated).

Parameter	Plant C		Plant D	
	Concentration	Range	Concentration	Range
pH	11.0	10.9 - 11	11.6	11.5 - 11.7
EC	3.1 mS/cm	3.1 - 3.5	5.2 mS/cm	5.1 - 5.3
Elutrient Colour	amber		brown	
	(total concentration)		(total concentration)	
Antimony	0.15	0.14 - 0.18	0.035	0.019 - 0.087
Arsenic	<0.5		<0.5	
Barium	<0.1		<0.1	
Beryllium	<0.1		<0.1	
Boron	0.5	0.5 - 0.6	0.3	0.3 - 0.4
Cadmium	0.5	0.2 - 0.6	<0.1	
Chromium	153	150 - 164	0.1	0.1 - 0.2
Cobalt	<0.1		<0.1	
Copper	0.2	0.1 - 0.3	<0.1	
Lead	0.4		<0.4	
Manganese	9.3	9.1 - 9.6	0.2	0.2 - 0.3
Mercury	<0.05		<0.05	
Molybdenum	16.2	15.2 - 18.0	0.9	0.7 - 0.9
Nickel	31	31 - 34	0.1	0.1 - 0.2
Nitrogen	13,900	12,800 - 16,000	42,400	42,400 - 43,400
Selenium	<2		<2	
Silver	<0.01		<0.01	
Tin	<0.2		<0.2	
Vanadium	0.7	0.6 - 0.7	<0.1	
Zinc	5.3	5.2 - 5.9	1.5	1.4 - 1.5
	(soluble concentration)		(soluble concentration)	
Calcium	6	3 - 6	4	3 - 6
Magnesium	<1		<1	
Potassium	46	45 - 47	45	44 - 45
Sodium	10,300	10,000 - 11,200	13,700	13,200 - 14,000

TABLE 3

GC/MS ANALYSIS OF TWO DEA FILTER SLUDGES FOR AMINE COMPOUNDS

Plant A DEA filter sludge		Plant B DEA filter sludge	
Compound	Concentration	Compound	Concentration
H_2N-CH_2-R	532 ppm	Diethanolamine	57,000 ppm
Diethanolamine	480	N,N'-bis(2-hydroxyethyl) piperazine	7,800
Unknown, not N-containing	26,620	Monoethanolamine	7,100
Unknown, difficult to interpret	7,300	Triethanolamine	6,800
		N-(2-hydroxyethyl)piperazine	6,000
		N,N'-bis(2-hydroxyethyl)imidazolidone	2,700
		N,N,N'-tris(2-hydroxyethyl) ethyldiamine	2,500
		Unknown, N-containing, mw 277 - 392	36,800
		Unknown, not N containing, mw 304, 372	13,100
Total	23,232	Total	139,800

TABLE 4

GC/MS ANALYSIS OF TWO MEA RECLAIMER BOTTOMS FOR AMINE COMPOUNDS

Plant C MEA reclaimer bottoms		Plant D MEA reclaimer bottoms	
Compound	Concentration	Compound	Concentration
N(2-hydroxyethyl)piperazine	57,000 ppm	Monoethanolamine	82,000 ppm
$HN(C_2H_4OH)$-CH_2R	14,300	N(hydroxyethyl)imidazolidone	34,000
Unknown ethanolamine	10,300	N(hydroxyethyl)N'-methyl imidazolidone	17,000
Diethanolamine	6,000	2-(2-aminoethoxy)ethanol	12,000
H_2NCH-R, mw 405	4,600	Glycine	6,300
2-hydroxyethyl-methylamine	2,800	N-methyldiethanolamine	5,700
H_2NCH_2-R, mw 389	2,700	N(2-hydroxyethyl)-1,2-ethylenediamine	4,700
Polycyclic, N containing	2,500	2-ethylhydroxy-3-propylhydroxyamine	4,400
Unknown cyclic ethanolamine	2,400	Unknown, N containing, mw 276, 320, 395	22,000
N,N'-bis(hydroxyethyl) ethylenediamine	1,900	Unknown, not N containing, mw 198, 296	8,700
N(hydroxyethyl)-1,2-ethylenediamine	1,800		
Unknown, N containing, mw 263 - 386	29,600		
Unknown, not N-containing, mw 230	7,200		
Total	143,100	Total	196,800

TABLE 5

ORGANIC COMPOUNDS IDENTIFIED IN AMINE RECLAIMER BOTTOMS AND LEAF FILTER SLUDGES (58)

Reclaimer Bottoms

Compound	Range	Compound	Range
Phenol	4 - 8 ppm	Methyl phenol	3.5 - 3 ppm
Dimethyl phenol	2	Ethyl phenol	0 - 0.1
Ethyl benzene	0 - 0.7	Dimethyl benzene	0 - 3
Aliphatic acids (C2 - 17)	0 - 7*	Tetradecanoic acid, ester	0 - 1
Hexadecanoic acid ester	0 - 1	Ethylhexanoic acid	0.2 - 1
Cyclic thioethers	0 - 1*	Unidentified acids	0 - 2
Pentathiepane	1 - 5.5	Ethenythio octane	0 - 0.1
Tetrahydro 1,1-dioxide thiophene	0 - 0.1	2-(2-phenoxy ethoxy)ethanol	0 - 0.2
Benzoic acid	0 - 0.4	Quinoxaline	0 - 0.07

Amine Leaf Filter Sludge

Compound	Range	Compound	Range
Asphaltene material	4350 ppm	2,6-dimethyl-2,5-heptadiene-4-one	2 - 3 ppm
Aliphatic acids (C6 - C8, C15, C17	0.4 - 5*	Phenol	0 - 0.1

* each compound

TABLE 6

CHANGES IN TOXICITY AFTER 6 WEEKS INCUBATION

(Toxicity to bacteria and fish of liquid elutrient from a 10% sludge/soil mixture and to germinating seeds of a 5% sludge/soil mixture).

	Plant A DEA filter sludge		Plant B DEA filter sludge	
Test organism	Week 0	Week 6	Week 0	Week 6
bacteria EC_{50}	62.7%	55.2% *	9.4%	76.4
seeds - 5% mix	100% germinated	100% germinated *	95% germinated	100% germinated *
fish LC_{50}	> 3%	> 3.2%	0.64%	0.5% *

	Plant C MEA Reclaimer Bottoms		Plant D MEA Reclaimer Bottoms	
Test organism	Week 0	Week 6	Week 0	Week 6
bacteria EC_{50}	11.8 %	20.9% *	12.7%	44.7%
seeds - 5% mix	5% germinated	0% germinated *	95% germinated	100% germinated *
fish LC_{50}	3.5%	6.4%	1.5%	6.4%

LC_{50} - Median Lethal Concentration
EC_{50} - Median Effective Concentration
* no significant change

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MINIMIZING ENVIRONMENTAL PROBLEMS FROM PETROLEUM EXPLORATION AND DEVELOPMENT IN TROPICAL FOREST AREAS

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Introduction

Tropical forest areas are highly vulnerable to serious and often irreversible environmental damage from poorly-planned development activities. However, if the proper environmental measures are adopted and rigorously followed, petroleum exploration and development in tropical forest areas need not cause major environmental damage. Moreover, most of these environmental measures do not significantly increase petroleum production costs; some can even reduce costs.

This paper outlines the basic measures needed to minimize environmental impacts from onshore petroleum exploration and development in tropical forest areas. The paper is based on the author's experience with petroleum development in the Amazon region of South America; however, the recommendations provided here are likely to prove useful for petroleum work in tropical forested countries worldwide. The paper focuses on the most critical environmental issues involving petroleum exploration and development in tropical forest areas; it does not address certain lower-priority environmental problems (such as carbon dioxide emissions from the flaring of natural gas).

Oil companies can help ensure that environmental measures such as those outlined below are followed by codifying them (as specific policies and procedures) within an Environmental Manual. Such a Manual should specify the practices needed to minimize negative environmental impacts from each phase of petroleum development, including seismic investigations, exploratory and production drilling, pipelines, storage, refineries, and ports. The Manual should be detailed and explicit, so that it would be clear when contractors or employees are (or are not) following its rules.

Road Construction

In most tropical countries (particularly in Latin America), the most severe environmental impact from petroleum development is the colonization and deforestation that follows the penetration of forested areas by oil industry roads. Much of this colonization and deforestation takes place on lands which are unsuited for sustainable agricultural development. For example, recent unofficial estimates by a Bank mission in one Amazonian country indicate that, in the absence of specific measures to control colonization, each kilometer of new road built by the oil industry through forest results in the colonization of 400-2,400 hectares.

To minimize deforestation, oil companies therefore need to minimize the kilometers of new roads constructed within most forested areas. The layout of any new roads through forested areas should be carefully planned, to minimize their length. In some cases, the supplemental use of rivers for transporting supplies can reduce the kilometers of road built. Whenever economically feasible, exploratory drilling sites in forested areas should be reached by using helicopters, rather than by constructing access roads. Perhaps most importantly, new production drilling operations in forested areas should construct cluster drilling platforms (as Conoco plans to use in Ecuador's Yasuni National Park), rather than dispersed individual wells. This can greatly reduce the kilometers of new roads needed.

Prior to building new roads through forested areas with special legal protection (such as National Parks, Forest Reserves, or Indigenous Reserves), the responsible oil company should financially support a 24-hour roadblock and a regular system of patrols to prevent illegal colonization. This can be done through legal agreements with the relevant land management agency (Park Service, Forest Service, Agrarian Institute, or other agency). Locating the oil workers' camp just outside the entrance to the protected area can also help to deter colonization. Properly staffed roadblocks can also be used to control the transportation of illegally cut logs, wildlife products, or other contraband from the forest. After they are no longer needed (such as when petroleum reserves have been commercially depleted, or after unsuccessful exploratory drilling), roads built through unpopulated, forested zones should normally be decommissioned (such as by removing the bridges). This would greatly reduce future risks of colonization and deforestation in the area.

Environmental Manuals should specify maximum widths for various types of oil roads through forested areas. In some cases (especially in flat terrain), forest canopy cover can be maintained, so that the road need not be a barrier to the movements of monkeys and other arboreal wildlife. Environmental Manuals should also specify environmentally appropriate road construction materials and techniques in forested areas. Whenever possible, geo-textiles or geo-plastics (woven polyvinyl chloride or polypropylene) should be used as road construction support material,

because they reduce the requirements for timber and gravel. To the extent that any timber is used for the road base, it should come entirely (or as much as possible) from trees that are cut for the road right-of-way. For clearing the road right-of-way, trees should be felled with chainsaws rather than bulldozers. (Unlike chainsaws, bulldozers disturb the soil and tree roots; they also tend to damage many more trees outside the road right-of-way.) The Manuals should also indicate under which conditions gravel, heavy oil, or other materials can be used for road surfacing. (When oil is used for road surfacing, some of it washes away into streams; however, gravel mining disturbs river ecosystems.)

Roads constructed across streams should provide for proper drainage, such as through the use of pipe or box culverts. This is needed to avoid partially damming small streams, which blocks the migration of fish and other aquatic life, kills trees and increases mosquito habitat upstream of the road, and reduces water flow downstream. The culverts or other drainage systems require routine maintenance, so that they are not clogged with debris.

Some oil companies (both governmental and private) have "community relations funds", which are used to finance small-scale development projects in areas near the oil company facilities. These should not be used for building or improving roads through forested or legally protected areas. Rural roads financed through these special community programs should be subject to the same environmental criteria as roads planned for oil production purposes.

Management of Drilling Wastes

Spent drilling muds (which contain various toxic substances) should be landfilled in dry pits, or in sumps from which the water has been piped out. The landfill pits should be lined with a suitable substance (such as plastic) to minimize risks of groundwater contamination. The landfilling should take place before the site is abandoned, while on-site bulldozers are still available.

Formation water produced from drilling operations is oily, often extremely salty, and contains various toxic compounds. Whenever feasible, formation water should be reinjected into the ground. In any cases where this might not be feasible, the formation water that is not recycled (such as to formulate new drilling muds) should be treated on-site, prior to being discharged in adjacent waterways. Simple on-site treatments include aeration spraying or cascading for oxygenation and cooling, skimming of surface oil, flocculation and settling to remove certain salts, and dilution with fresh water. These treatments should also be used (as needed) for water piped out of oil sumps.

While they are in use (prior to eventual landfilling), oil sumps

(piscinas) should be screened from above with 2 cm (or finer) mesh nets, to prevent birds, mammals, and larger insects from entering the sump and being trapped and killed by the surface oil. Nets such as these are now legally required in parts of the United States; their cost is insignificant, relative to the costs of drilling each well.

Prevention and Control of Oil Spills

Environmental Manuals should specify design standards for any new pipelines for petroleum and its derivatives (as well as natural gas). These standards should indicate the proper spacing and types of valves and automatic shut-off mechanisms, to minimize damage from pipeline leaks. Pipelines should often be buried for environmental reasons--for example, to reduce forest clearing for the right-of-way, or to reduce risks of damage from vehicle crashes along highways. To the extent feasible, pipelines and their associated service roads should be re-routed around environmentally sensitive areas, such as National Parks and equivalent reserves.

Oil storage tanks need permanent earthen levees around them; the levees should be dimensioned such that they can contain all of the oil from the storage tanks, in case the latter should rupture. Refineries need appropriate water pollution control equipment, proper operational and maintenance procedures for this equipment, and staff who know how to operate and maintain the equipment. All infrastructure which holds petroleum or its derivatives (including pipelines, storage tanks, and refineries) should have a precise schedule of routine maintenance, including periodic replacement of parts, to minimize risks of spills or other malfunctions due to poor maintenance. Spent motor oil and similar wastes should be collected in barrels and burned or landfilled--not discharged into streams, rivers, or lakes. No washing of motor vehicles in streams and rivers should be permitted.

Strict adherence to these measures should minimize the frequency and magnitude of accidental oil spills. However, some accidental spills are inevitable (such as when Ecuador's main oil pipeline ruptured in 1987 after a massive earthquake and resulting landslides). It is therefore important for oil companies to develop Oil Spill Contingency Plans that encompass all of their pipelines, storage tanks, refineries, ports, and similar facilities. Contingency Plans should outline specific technologies and control systems, sites where control equipment and available personnel are to be based, an adequate budget and source of financing, the division of institutional responsibilities between the oil company and national and local Government agencies, and a schedule for rehearsal of oil spill containment and clean-up operations. Oil companies should also develop efficient administrative mechanisms for processing legal claims for economic damages resulting from oil spills.

Land Management at Petroleum Facilities

New camps built in forested areas should not use more land than is required for buildings, recreational purposes, and safety considerations. Some oil company camps in Latin America occupy many more hectares of once-forested land than necessary, due to their huge lawns and overly wide streets.

After drilling or other operations which involve land clearing or excavation are terminated, all cleared land should be rehabilitated. In humid tropical zones such as Amazonia, simply spreading out the soil which was originally scraped off during site preparation will generally promote rapid natural revegetation. In such cases, manual reforestation or other intensive landscaping are usually not needed.

In all types of petroleum exploration and development areas (including seismic study sites), all non-biodegradable solid wastes (such as plastics) should be deposited in small, on-site landfills. "Littering" with any such wastes should be strictly prohibited.

Managing the Activities of Oil Workers

All fishing (especially with dynamite or poisons) and hunting by oil workers should be strictly prohibited, because it greatly increases the local environmental impact of seismic studies or drilling activities. Oil companies and contractors therefore need to transport sufficient quantities of food to their workers.

Whenever possible, firearms should be completely prohibited from remote, forested oil exploration or production areas. In countries where guerilla groups are nonexistent, firearms are not needed for "protection". In those countries where a legitimate need for firearms may exist due to local political instability, pistols should be used (whenever possible) rather than rifles or shotguns (because they are less effective for hunting), and supplies of ammunition should be tightly controlled and monitored.

Mobility restrictions should be enforced for oil workers in forested or other environmentally sensitive areas. In particular, oil workers should not be allowed to stray from camp in areas anywhere near indigenous populations. Also, no alcohol should be permitted in such areas.

Oil companies should specify (within their Environmental or other Manuals) and implement appropriate occupational safety standards and procedures. The World Bank's Occupational Health and Safety Guidelines can be a useful reference in this regard.

Institutional Aspects

Effective institutional mechanisms are needed to ensure that the rules set forth in Environmental Manuals are actually followed in remote, forested areas. For example, bidding and contracting documents should explicitly outline all necessary environmental protection measures (as specified in the Environmental Manual). Financial penalties (large enough to serve as effective deterrents) should be specified for all violations of this Manual by contractors and concessionaires (including transnational oil companies). A transparent system of penalties (fines, suspension, or termination) should also be established for individual employees of oil companies or contractors, for each type of violation of the Environmental Manual.

Environmental Manuals are effective only to the extent that sufficient environmental staff are available to ensure their implementation. It is therefore important for oil companies to hire an adequate number of environmental staff, and to establish some type of in-house environmental unit. Environmental Manuals should indicate the number, specific duties, and necessary qualifications of on-site environmental control officers needed for each type of petroleum exploration and development activity, along with the approximate budget allocations needed to support these staff in the field. Besides operational activities, some staff should be responsible for routine, on-site environmental monitoring of water quality, aquatic life, and other environmental indicators.

To ensure that the environmental staff of petroleum companies are well-qualified to carry out their responsibilities, some type of environmental training is usually necessary. Environmental training options (which should be tailored to the specific needs of each oil company's environmental unit) include short, locally-organized courses on environmental assessment and mitigation; working as counterparts with environmental consultants on specific tasks (such as environmental impact studies of proposed new projects); participation in overseas special courses (such as those offered by the Center for Environmental Management and Planning of the University of Aberdeen, Scotland) or conferences (such as this symposium); and scholarships for master's or other degrees in environmental sciences at national or foreign universities.

Environmental Manuals should specify the legal framework (including laws, regulations, and administrative decrees) upon which they are based. Ideally, the Manuals should be public documents, and copies should be readily available to interested non-governmental organizations and members of the public.

In Ecuador, Petroecuador is currently preparing a comprehensive Environmental Manual for its operations, which take place largely in the ecologically sensitive Amazon region. After it is complete,

Petroecuador's Environmental Manual might possibly serve as a model for other petroleum companies interested in preparing or revising their own environmental manuals. However, each company's Environmental Manual will differ somewhat, depending on the host (or parent) country's environmental laws and institutions, the portfolio of activites undertaken by each oil company, and the types of ecosystems (forest or non-forest, onshore or offshore) in which petroleum exploration or development takes place.

The World Bank has recently adopted detailed policies on Environmental Assessment and Wildlands. The Environmental Assessment Policy requires that environmentally sensitive development projects have detailed environmental studies done prior to Bank financing, and that all feasible modifications be made in the project's design and operation to minimize any negative environmental effects. The Wildlands Policy seeks to minimize the elimination of wildlands (relatively unmodified natural ecosystems) in Bank-assisted projects, and requires the conservation of wildlands in certain types of projects. These policies are presently being implemented in a number of developing countries (including tropical forested ones) where the Bank is assisting the development of the petroleum and natural gas sector.

MOBIL WASTE MANAGEMENT CERTIFICATION SYSTEM

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INTRODUCTION

The real challenge for disposal of waste from the petroleum exploration and production industry is not the "why" nor the "how" but the "where" to safely dispose in consideration of the industries' responsibilities to our environment and future generations as well as present and future stockholders. These responsibilities are in fact one and the same and can be summarized in the words of Mr. William Reilly, EPA Administrator:

> "Act toward the future in such a way that you will have no reason to regret the past" (1).

There are ever increasing difficulties in establishing and maintaining sound waste handling and disposal systems. A constantly changing and growing regulatory matrix coupled with uneven enforcement from state to state make the role of the waste disposer a difficult one.

The lucrative nature of the disposal business attracts numerous investors and operators, which range from strictly honest to "snake oil salesman". Such a diversity of operators together with the fact that regulatory agencies often have difficulty attracting and maintaining highly qualified and experienced staff create the potential for the continued existence of inadequate facilities which will manifest future environmental problems.

This potential for inadequate facilities for offsite disposal creates a situation where the industry is responsible to examine its offsite waste disposal options in light of environmental adequacy. The importance of these evaluations is accentuated in light of environmental responsibility legislation and its consequences.

The cost to implement a system to examine offsite disposal facilities is small when compared to Superfund site remediation costs. The cost to cleanup a Superfund site has risen dramatically over the past few years. The government has set aside nearly $30 billion to cleanup the approximately 1200 sites

on the National Priority List (NPL) which averages around $25 million per site. Initially when the Superfund program was established it was estimated that the cost to cleanup a site would average $9 million. Over the years, the cost of site remediation has risen and now ranges between $21 and $30 million. With Superfund or similar (state) cleanups, generators are being charged a second time to dispose of waste they believed was adequately disposed of long ago. The disposal costs the second time around can be many times higher than the original disposal cost. Though many potentially responsible parties (PRPs) are liable for cleanup costs, the companies with the greatest assets are the ones who actually foot the bill. These staggering costs can often be avoided if time is spent reviewing a disposal facility's operations prior to shipping any waste.

DISCUSSION

Mobil's Waste Management Certification System is devised to assist the exploration and producing division personnel in deciding where to send waste for treatment and/or disposal. The system is designed to be used whenever a third party is contracted for treatment and/or disposal of Mobil's waste streams.

The system consists of three basic steps: 1. gathering the information about the facility, 2. comparing that information to certain decision criteria and 3. preparing the summary report on the suitability of the facility. Other components of the system include scheduling revisits of facilities and providing information to the field personnel for coordinating transport of waste streams to recommended waste treatment/disposal facilities.

Information Gathering

The first step is to gather as much pertinent information on the facility as possible. The information on a facility is divided into three areas: the institutional aspects, the operational/ physical aspects and the environmental aspects. Each of these aspects contributes to the overall evaluation of the facility.

Institutional information pertains to the description of the facility as it conforms to the Federal, state and/or local agency rules and regulations that govern it. This type of information is obtained from files in the Federal, state and local regulatory agency offices. The main sources of institutional information are the facility's permit application, regulatory files and permits. Interviews with the regulatory personnel familiar with the facility are informative and provide the agency's viewpoint of the facility and its operations. A financial report on the facility is obtained to help determine the financial stability of the company. It is desirable to collect and review this

information to have a preview of the facility prior to the onsite inspection. If the institutional information is complete and the facility complies with the regulations, then a facility inspection is scheduled. Serious deficiencies discovered at this point cause a facility to be eliminated from further consideration.

During the facility inspection, the information pertaining to operational/physical aspects is collected. A good source of this type of information is to interview the owner/operator of the facility. During the interview the treatment/disposal/recycle techniques are discussed to provide an understanding of how waste is handled and processed while at the facility. The evaluator should find out how materials are received (ie. manifests, bills of lading, etc.), how materials are processed or disposed and if any portion of the waste stream leaves the facility (ie. discharge, recycle, etc.). A tour of the facility is necessary to note and observe the size and location of tanks, ponds, pumps, dikes, filters, laboratory facilities, storage areas, etc. Monitoring well information, spill response, safety measures and other pertinent information can be discussed during the facility tour. Photographs are important and are taken, when allowed, to record conditions at the time of the visit and remain available for future reference. A checklist is compiled prior to visiting the facility which covers the items listed above, but is expandable to cover other items at the facility and special circumstances. The checklist should not substitute for alert and informed professional observation, work and judgment.

The environmental aspects of the facility are the third type of information collected. Environmental aspects include the surface hydrology, geology, soils, meteorology and groundwater hydrology. Sources for this information include published and unpublished reports on the geology, hydrology, soils, as well as, site data and data given in the permit application.

The soils, hydrology, geology and air emission (if applicable) information is very important since it defines the degree of environmental protection afforded by the facility. Review of monitoring well data provides insight to groundwater conditions and shows existing or potential groundwater problems. Meteorological information is necessary for performing mass balances on incoming and outgoing waste streams and for determining the effect of the weather on the facility and its operations.

Even though some of the information may not be site specific, it can provide base information for area conditions. Development of original data may be necessary to supplement areas where little or no data exists.

Decision Criteria

After collecting all the available information on the facility, the Decision Criteria is applied to the information. The designations of "Acceptable", "Acceptable With Problems" or "Unacceptable" are assigned to the facility based on sound supporting data. The criteria which are used to evaluate the facility are as follows:

1. Knowledge of the environment and the factors affecting the environment,
2. Consideration of how the waste processing method affects the environment, and
3. Knowledge of how the environmental factors affect the waste processing method.

The evaluator uses the available institutional, operational/ physical and environmental information as it applies to the above criteria. He also uses his knowledge about the facility, its operations and type of waste processed to make a recommendation on the facility.

"Acceptable" facilities have complied with the institutional information aspects and operate in a technically, environmentally and financially sound manner. These facilities generally have a simple treatment/disposal process and pose a low risk for environmental contamination. The owners/operators maintain their equipment, regulate their process and comply with applicable regulations.

Facilities that are "Acceptable With Problems" have deficiencies in one or more of the informational aspects. The facility is recommended for waste treatment/disposal, but the facility may exhibit a variety of minor environmental, operational or regulatory problems. The problems are not severe enough to reject using the facility, but on the other hand, the problems cannot be ignored or overlooked. These problems are highlighted to warn of potential environmental or regulatory concerns.

The evaluators must rely on their knowledge of the general environment, the type of process, the waste being processed and the potential for environmental contamination to make their recommendation. The available information is used to support the recommendation decision.

An "Acceptable With Problems" facility should be monitored on a frequent basis to ensure that the site doesn't develop more serious problems which could later render it unusable for waste treatment/disposal.

Facilities that are "Unacceptable" have deficiencies in one or more of the informational aspects, but the deficiencies are of a serious nature. This type of facility is not recommended for waste treatment/disposal because conditions exist to indicate that the facility is technically, environmentally or financially unsound. Though a facility may have a valid permit to operate, conditions may be present with the potential for environmental contamination, regulatory violations, or improper treatment and handling of a waste stream. These conditions could lead to future liability and adverse publicity for generators sending waste to the facility.

Summary Reports

After all the available information has been reviewed and the facility has been inspected, a summary report is written to highlight the important aspects of the facility. The reports include basic information such as the name, address and phone number of the facility, as well as short descriptions of the process, regulatory history, transportation modes, waste accepted and technical acceptability. The technical acceptability section allows for the listing of the reasons for recommending a facility "Acceptable", "Acceptable With Problems", or "Unacceptable".

The summary report should also include a permits matrix. The matrix lists the permits issued by Federal, state or local agencies for the various aspects of the facility's operations. The date issued and expiration date for each permit should be noted along with any special requirements or limitations imposed upon the facility.

Re-evaluation Frequency

The facility should be re-evaluated on a regular basis. The frequency of re-inspections is dependent on the amount and type of waste brought for treatment/disposal and the proximity of the facility to the waste generating site.

Repeat reviews of a facility are scheduled to ensure that the facility continues to operate in the manner described in the previous summary report. The revisit inspection should note any physical changes or operational modifications, as well as any changes in management or ownership. Periodic reviews of the facility's regulatory files may yield important information concerning operational modifications, closures, or physical changes to the facility. Other facilities in the area which are acceptable for waste treatment/disposal but not used should be re-inspected periodically to maintain a list of available back up facilities should the primary facility have problems. Alternate facilities should be available to keep pricing competitive for waste treatment/disposal, but should also have the ability to

properly handle the waste stream.

Each time a facility is re-evaluated a new summary report should be generated listing the new information and updating the regulatory history. The old summary report should be destroyed to avoid confusion with the updated report. The summary reports should be handled by one person or a small group of people (waste coordinators) to maintain control over the facility review system. The waste coordinators communicate with field personnel regarding facilities that have been reviewed or need to be reviewed.

Summary List

Aside from the Summary Report, a Summary List should be assembled. The Summary List contains a brief description of the facility, its address, phone number, waste types and its technical acceptability with some abbreviated supporting information. Only the summary list information is provided to the field personnel since they need to know the facilities that are approved to accept their waste stream.

System Implementation and Operation

The Mobil Waste Management Certification System was implemented in the fall of 1988 for all Mobil Exploration and Production wastes generated in the U.S. Prior to that time, the system had been operational on a pilot basis in several divisions.

The number of non-hazardous waste facilities approved for use and being utilized for disposal far outnumber the hazardous waste facilities. Exhibit 1 presents a schematic of the major evaluation categories and elements in the system. Clearly it is not always sufficient to evaluate only the facility in question, but related facilities which may further handle by-products of the subject facility (eg: waste taken to wastewater facilities such as injection wells and treatment operations, recycle facilities, landfills, etc.) must also be reviewed. Each step in the web of disposal must be evaluated to provide a complete environmental picture upon which an effective recommendation can be made. Exhibits 2a and 2b illustrate the types or categories of non-hazardous waste facilities evaluated under the Mobil Waste Certification System and provides information on the number found to be Acceptable, Acceptable With Problems or Unacceptable for each category of facility. The number of non-hazardous waste facilities evaluated, as taken from Exhibits 2a and 2b, is approximately 215, with 33 Acceptable facilities, 95 Unacceptable facilities and 87 facilities Acceptable With Problems.

Exhibit 3 illustrates the types or categories of hazardous waste facilities as well as the number of sites found to be Acceptable,

Acceptable With Problems or Unacceptable for each category of facility. Out of the 24 hazardous waste facilities there was 1 Acceptable facility, 13 facilities Acceptable With Problems and 9 facilities that were Unacceptable.

Exhibit 4 shows that 15 percent of the non-hazardous facilities evaluated were determined to be Acceptable, 40 percent were Acceptable With Problems and 45 percent were Unacceptable. With respect to the hazardous facilities evaluated, 4 percent were Acceptable, with 58 percent Acceptable With Problems and 38 percent Unacceptable.

SUMMARY AND CONCLUSIONS

The Mobil Waste Management Certification System has in the short period of time since its implementation proved to be a valuable tool in helping to answer the question of "where" to dispose of the company's petroleum exploration and production wastes. The system as currently operated has not been manpower intensive or overly expensive. The expense of operating this type of system has already been saved many times over as a result of avoiding just one Superfund site cleanup involvement that we are aware of at this time. The key to success is diligence and the acute awareness that you are dealing with a dynamic rather than a static system.

REFERENCES

1. W. K. Reilly, What We Can Do, EPA Journal, 2, 1990, 32-34.

EXHIBIT 1

MOBIL WASTE CERTIFICATION SYSTEM EVALUATION SCHEMATIC

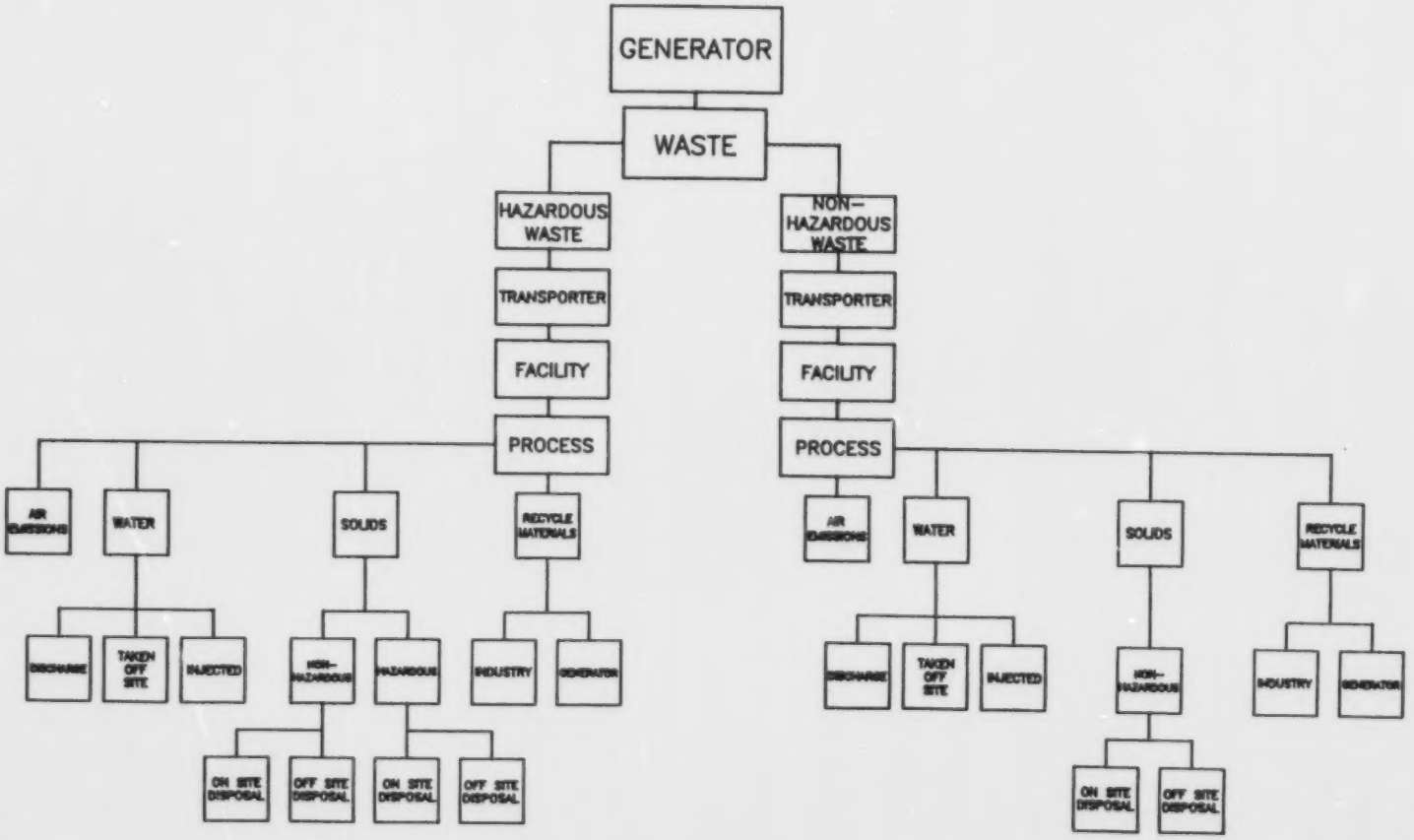


EXHIBIT 2a

NON-HAZARDOUS WASTE FACILITIES
NUMBER PER CATEGORY

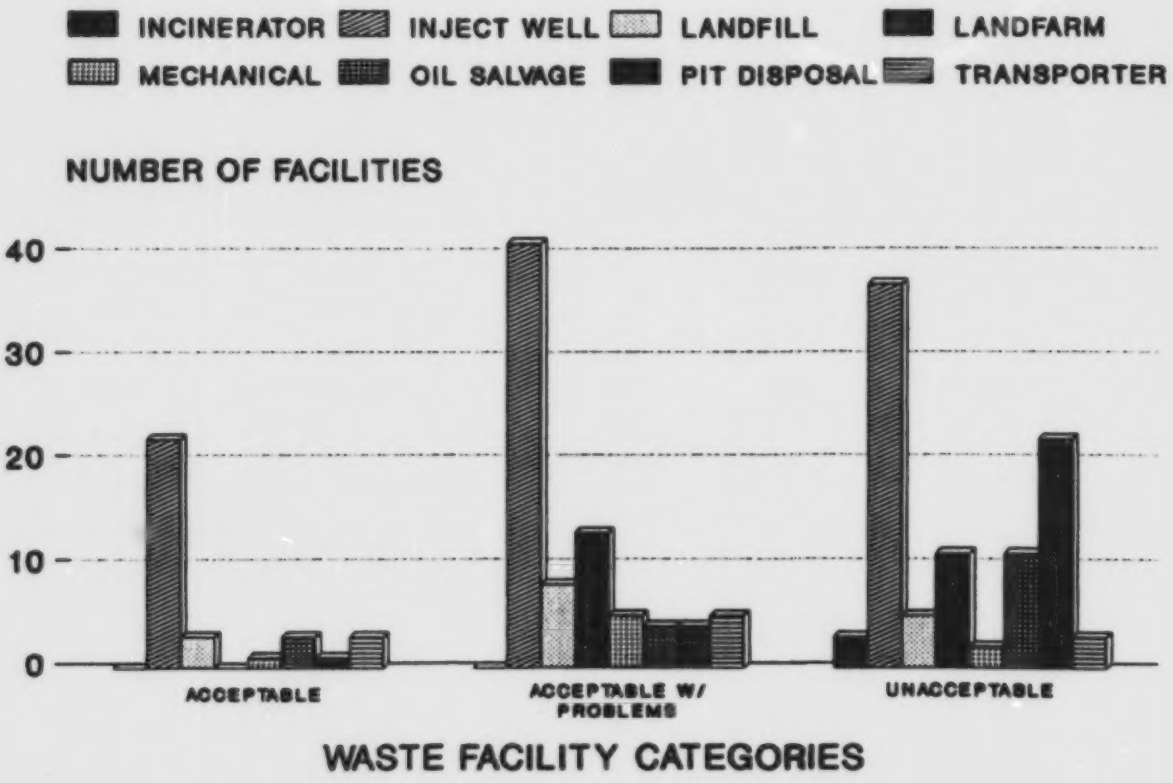


EXHIBIT 2b

NON-HAZARDOUS WASTE FACILITIES
NUMBER PER CATEGORY

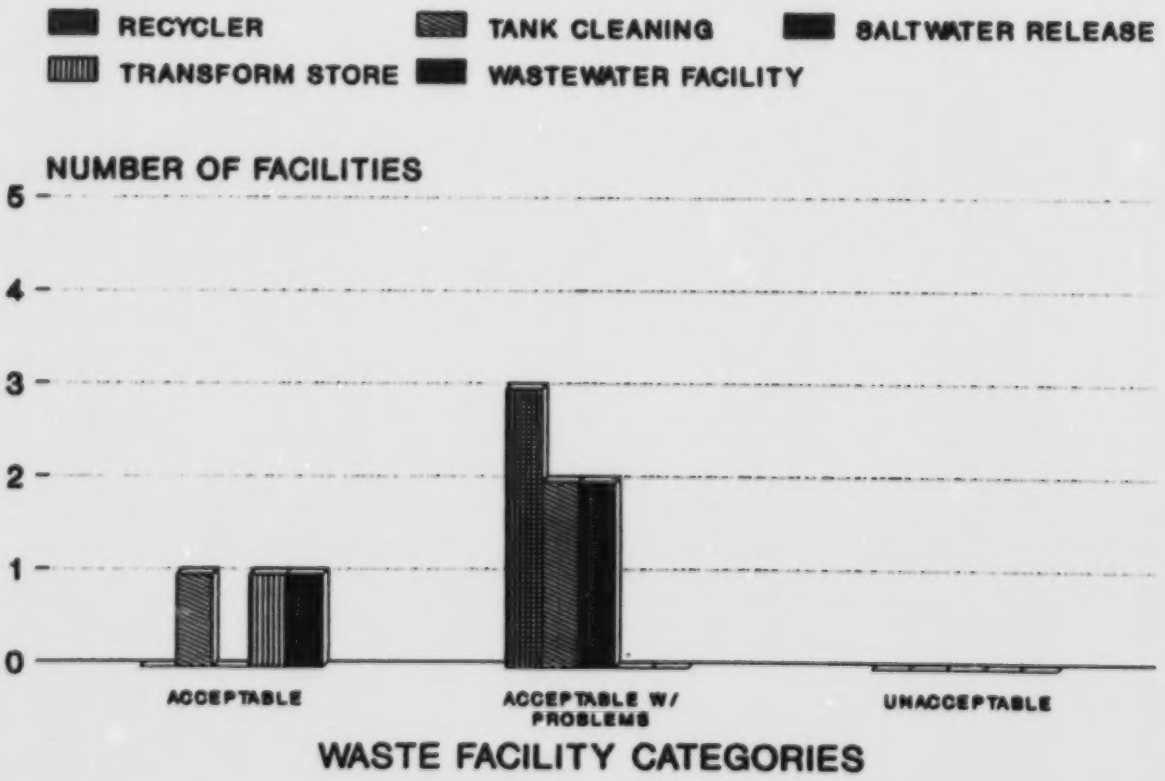


EXHIBIT 3

HAZARDOUS WASTE FACILITIES
NUMBER PER CATEGORY

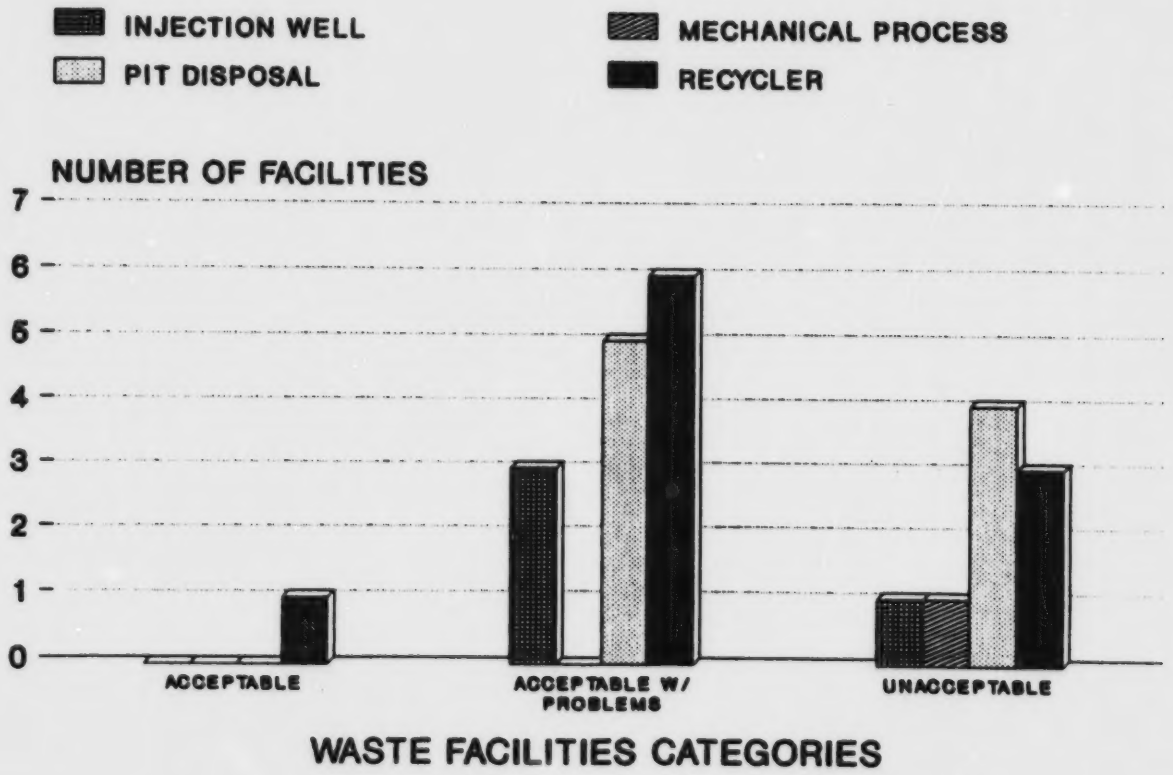
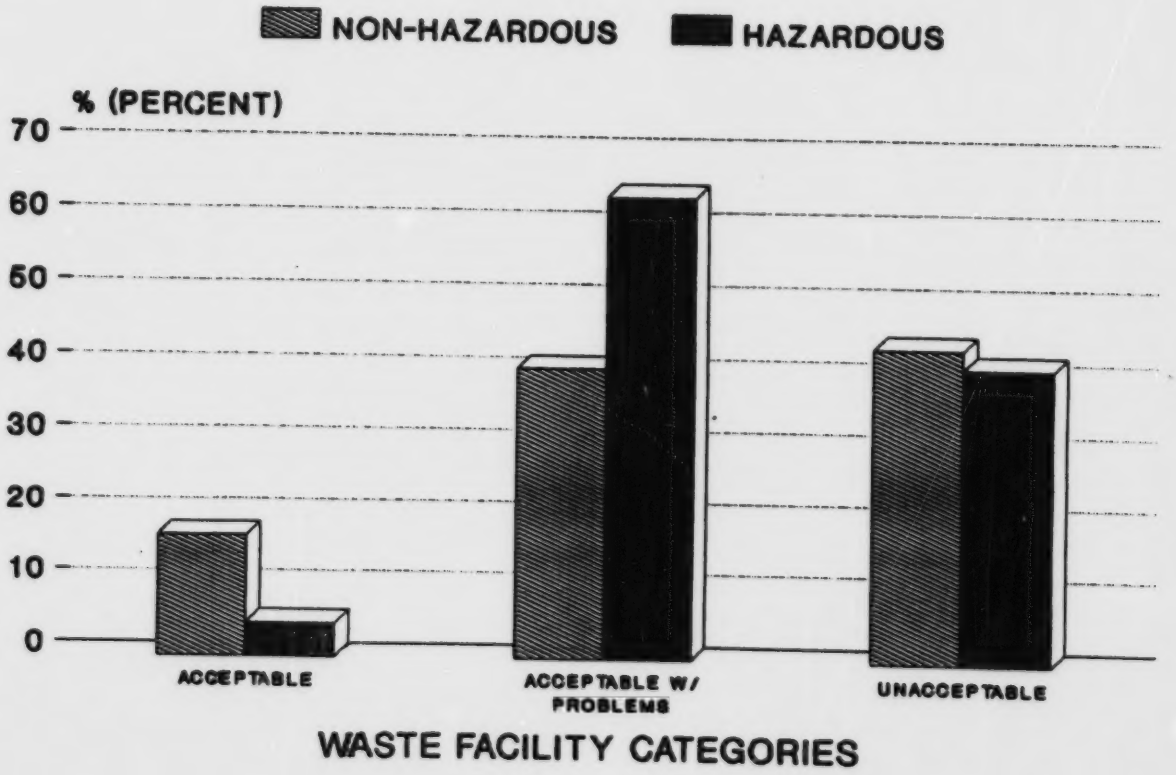


EXHIBIT 4

RATINGS OF WASTE FACILITIES
PERCENT PER CATEGORY



MODELLING OF TOLUENE MIGRATION IN GROUND WATER WITH THE USE OF A MULTIPHASE SIMULATION PROGRAMME

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Introduction

During the investigation of contaminated sites, problems of ground water protection for which the application of transport models is plausible are frequently encountered. If, for example, contamination of the ground water has been ascertained, the evolution of the pollutant distribution can be predicted by numerical analysis. Furthermore, if information on the suitability of a site for the disposal of hazardous waste is required, the consequences of the potential migration of pollutants can be appraised, and the associated risks can be estimated with the aid of models. Ground water flow is generally modelled by one phase flow regime with component transport on the basis of finite element solutions of the differential equations (1,2,3). Practical decisions on the location of well sites for the decontamination of aquifers by the extraction of polluted water can be appropriately selected on the basis of predictions on the pollutant distribution. Numerical methods also permit a mutual comparison of various concepts of hydraulic remediation of contaminated sites.

Oil spills, groundwater contamination by hydrocarbon phases and biogenetic gas transport cannot be predicted by the use of one phase flow models or steady state flow approaches (4,5).

In the following, a particular case is described for demonstrating the application of a multiphase flow model developed in the oil and gas industry for assessing the potential hazard of ground water contamination by toluene invasion, as well as planning and designing of decontamination wells. Several concepts for hydraulic decontamination are thereby compared and appraised.

Description of the simulation programme for multiphase flow

The simulation programme employed for the analysis of multiphase flow has its origin in the field of oil and gas reservoir simulation. It is capable of modelling two liquid phases and one gas phase. Furthermore, the gas is soluble in one of the two liquid phases. The mass transport is described by the Darcy equation. Diffusion processes are not considered. The partial differential equations which apply to the fluid transport (see figure 1) are transformed to finite difference equations and solved by fully implicit procedures. The particular solutions must describe the variations in pressure and saturation as well as the mass transfer for every time interval in the blocks of the model zone (6).

liquid 1:
$$\nabla \left[\frac{kk_{r1}}{B_1 \mu_1} (\nabla p_1 - \gamma_1 \nabla D) \right] - q_1 - q_{mk_1} = \frac{\partial}{\partial t} \left(\frac{\Phi S_1}{B_1} \right)$$

liquid 2:
$$\nabla \left[\frac{kk_{r2}}{B_2 \mu_2} (\nabla p_2 - \gamma_2 \nabla D) \right] - q_2 - q_{mk_2} = \frac{\partial}{\partial t} \left(\frac{\Phi S_2}{B_2} \right)$$

gas:
$$\nabla \left[\frac{kk_{rg}}{B_g \mu_g} (\nabla p_g - \gamma_g \nabla D) + R_s \frac{kk_{r2}}{B_2 \mu_2} (\nabla p_2 - \gamma_2 \nabla D) \right] -$$

$$(q_g + R_s q_2) - (q_{mk_g} + R_s q_{mk_2}) = \frac{\partial}{\partial t} \left[\Phi \left(\frac{S_g}{B_g} + \frac{R_s S_2}{B_2} \right) \right]$$

Figure 1: Fundamental equations of the simulation programme

Nomenclature:

k	absolute permeability, m^2
k_r	relative permeability
B	bulk volume correction factor, as a function of the pressure and temperature
μ	dynamic viscosity, Pas
p	hydraulic pressure, Pa
γ	specific weight, Nm^{-3}
q	pumping rate, $m^3 s^{-1}$
Φ	porosity
R_s	gas solubility in liquid, m^3 gas / m^3 liquid
D	depth, m
t	time, s

The finite difference equations are formulated into an algebraic matrix system and solved iteratively. The specification of defined initial and boundary conditions is thereby vital. Thus, a prevailing, defined initial pressure distribution may either obey hydrostatic laws or require additional hydraulic pressure gradients upon extraction or injection of liquid through wells and other fluid supply sources. For multiphase flow, an effective permeability is entered as measured value, instead of the absolute permeability. Since a finite interfacial tension prevails between the phases, effects of capillary pressure have to be taken into account in the flow model. These data must also be provided from laboratory measurements.

Modelling of the aquifer

The next step leading from the basic mathematical model to the flow model for appraising a stratum which contains contaminated ground water comprises the transformation of the geological information of the model region under consideration to a block grid model.

In accordance with the geological description, the aquifer has an average thickness of about 30 m and consists of a Quarternary stratum of coarse sand to gravel with a thickness of about 10 m, a permeability of 50 to 80 Darcy (5 to 8 $\cdot 10^{-4}$ m/s), and an effective pore volume of 25 to 40 per cent, followed by a Tertiary intercalation of silts, clays, and sands with a thickness of 20 m. The ground water barrier is situated underneath, the cover is a layer of soil fill about 2 m thick. A three-dimensional model 180 x 280 x 9 m in size has been selected for modelling a section of the contaminated terrain and the adjacent region (see figure 2).

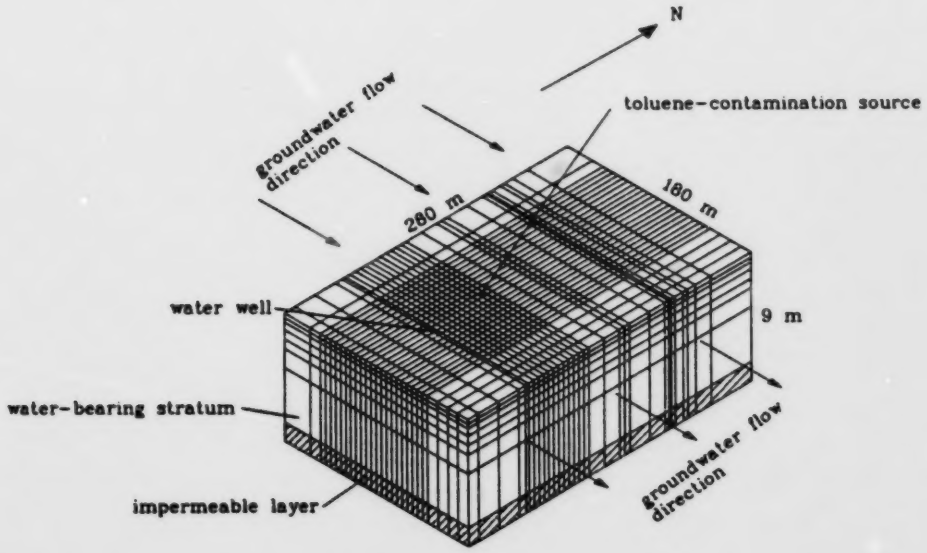

Figure 2: Grid model of the aquifer

The model is illustrated with grid subdivision in figure 2. For the first approximate analysis of the pollutant propagation, only the Quarternary aquifer stratum was considered. The fundamental data for the two-horizons model are compiled in table 1. The aquifer is subdivided into seven layers by the grid.

Table 1: Basic data for the two-horizons model

Dimensions:	280 x 180 x 9 m
Stratigraphic dip:	2 per cent
Aquifer:	
Porosity:	40 per cent
Permeability:	
parallel with stratification:	$5 \cdot 10^{-4}$ m/s
perpendicular to stratification:	$2.5 \cdot 10^{-4}$ m/s
Connate water saturation:	5 per cent V_p
Immobile oil saturation	0 per cent
Barrier stratum:	
Porosity:	5 per cent
Permeability:	
parallel with stratification:	$4 \cdot 10^{-9}$ m/s
perpendicular to stratification:	$2 \cdot 10^{-9}$ m/s
Average migration velocity of ground water:	0.1 m/d
Contamination with toluene:	
Location:	cross-hatched area
Quantity:	1000 l
Surface area:	25 m^2

Important basic assumptions in this case are the connate water saturation of about 5 per cent, which is plausible for a coarse-grained porous sediment, and an irreducible toluene saturation of 0 per cent. This implies that all of the free toluene is regarded as mobile, and that "droplet transport" is thus also possible. Binding of toluene by adsorption in the soil is not excluded. Special computer programmes are available for modelling processes of this kind; however, they have not been employed here because of the prime objective of this study.

Two forces are decisive for the transport of toluene in ground water:

⇒ the hydraulic flow of the ground water, and

⇒ the buoyancy force of toluene, whose density is lower than that of water.

The physical properties of water and toluene, as employed in the calculations, are presented in the following table.

Table 2: Physical data for the migration analysis

Density of water:	1000 kg/m^3
Viscosity of water:	$1 \cdot 10^{-3}$ Pas
Density of toluene:	881 kg/m^3
Viscosity of toluene:	$6 \cdot 10^{-4}$ Pas

The relative permeabilities of water and toluene are plotted in figure 3. The curve allows a high mobility for ground water and for toluene. since the critical phase saturation has been chosen as 5 and 0 per cent, respectively.

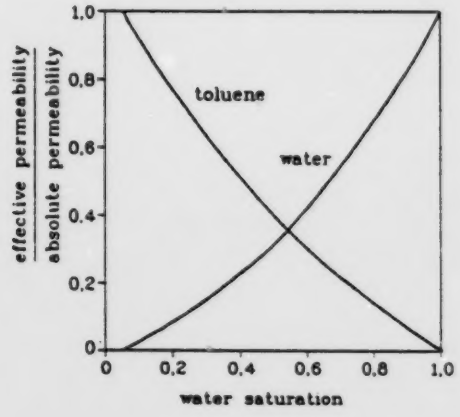

Figure 3: Relative permeabilities: toluene - water

Migration of toluene in the aquifer

On the basis of the present ground water flow velocity of 0.1 m/d, a balance prevailed between the buoyancy force of the less dense toluene and the hydraulic forces of ground water flow in the downward direction. Consequently, the zone of contaminated ground water propagated in a nearly steady-state manner. As a result of water extraction from a well located at a distance of about 50 m from the zone of toluene invasion, the contaminant stream was drawn in the direction of the well. After about 20 days of pumping, the toluene had already reached the well; subsequently, several litres of toluene were recovered from the well. The production of the well was terminated then.

By means of several observation wells in the surrounding area further distant from the source of pollution, checks were conducted in order to determine the direction of propagation of the toluene by the groundwater flow. The propagation of toluene about 1.5 years after the pollution happened, that is, at the beginning of the hydraulic remediation, is depicted in figure 4, as calculated with the simulation programme. A conspicuous feature is the fact that the highest concentration of toluene is still located in the vicinity of the pollution source, although a streak of toluene has drifted toward the well.

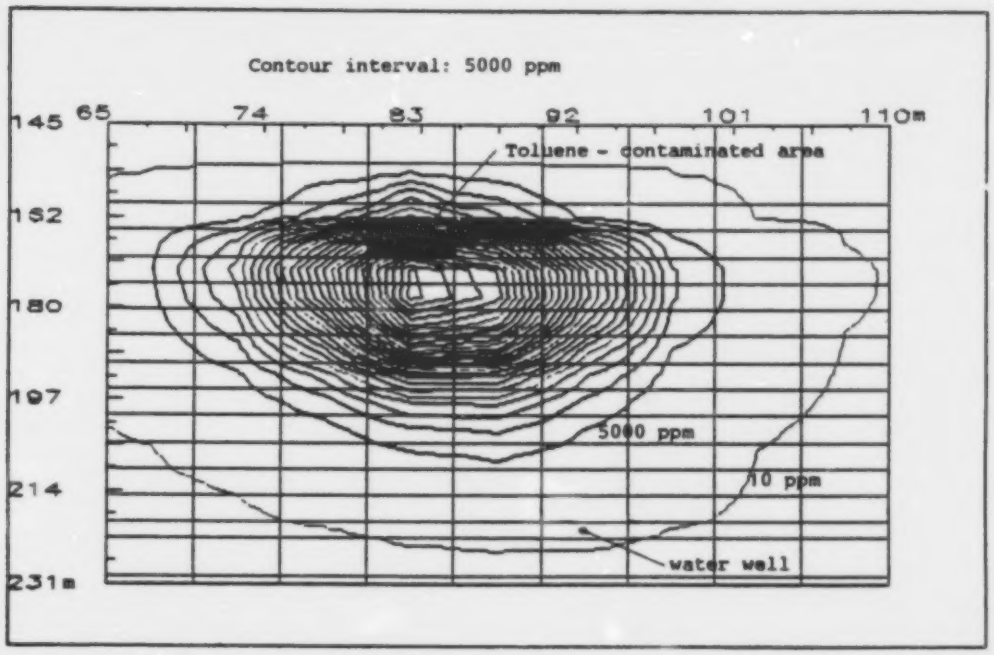

Figure 4: Migration of toluene in the aquifer, concentration of toluene in the bulk stream

Hydraulic decontamination of the aquifer with different well configurations

Hydraulic decontamination measures can be implemented for remediation of the aquifer because of the excellent permeability of the water-bearing stratum. Vital prerequisites for this purpose are the determination of optimal locations for the decontamination wells, on the one hand, and the choice of the necessary water pumping rate for complete removal of toluene from the ground water, on the other hand. Two possible remediation concepts with different arrangements of the decontamination wells are illustrated in figure 5.

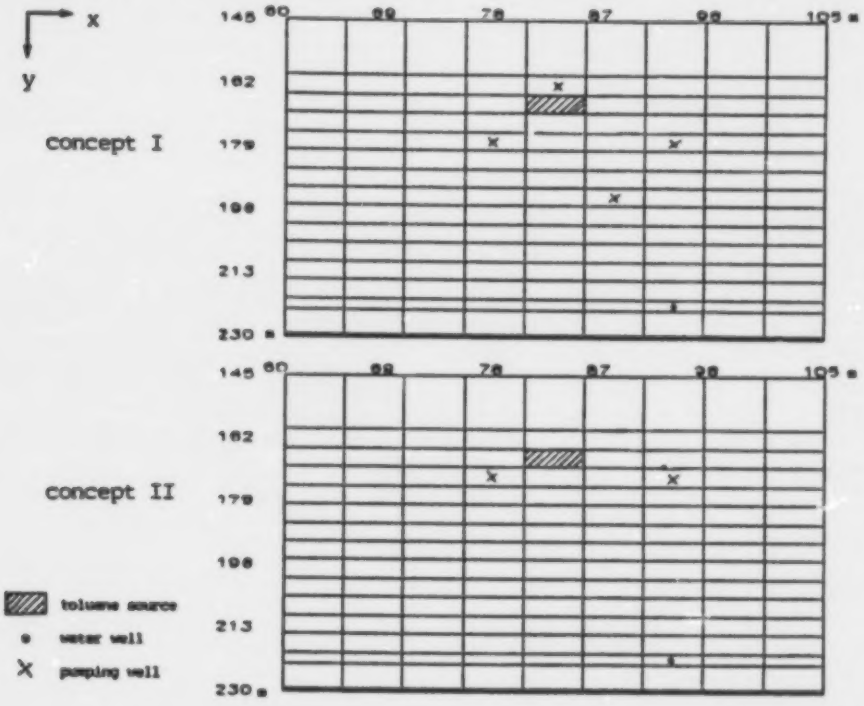

Figure 5: Different concepts for decontamination

In accordance with concept I, four additional wells are drilled in the regions surrounding the centre of contamination along an isoline of concentration of toluene, and water is recovered from each well at a pumping rate of 7 l/s (or about 605 m^3/d). In contrast, concept II provides for only two supplementary wells at the northern edge of the contaminated area, as well as the use of the existing well situated at a distance of about 50 m from the centre of contamination for the remediation. The total water pumping rate remains the same; hence, the southern, more remote well is operated at a water pumping rate of 14 l/s (or about 1210 m^3/d) with concept II, which involves only three decontamination wells.

Decontamination concept I:

The effect of the decontamination concept involving four additional wells is shown in figure 6. A decided decrease in the toluene concentration is already evident in the vicinity of the contamination centre after ten days. At the same time, a subdivision of the existing pollution area into two sections can be observed during extraction of the contaminated water by pumping; that is, two centres of concentration are formed. After a further period of twenty days, that is, thirty days after the beginning of the pumping test, only small amounts of toluene are still present in the ground water (see figure 7). After continuation of pumping for additional twenty days, no toluene remains in the original centre of contamination. A slight residual concentration is still present only in the vicinity of the well located at a distance of 50 m to the south, where the toluene mishap was observed. However, this residue, too, is completely eliminated by pumping after a further period of twenty days. These observations can be summarized by stating that no toluene is present in the ground water after extraction of the contaminated water by pumping for seventy days; that is, the completed decontamination operation is successful.

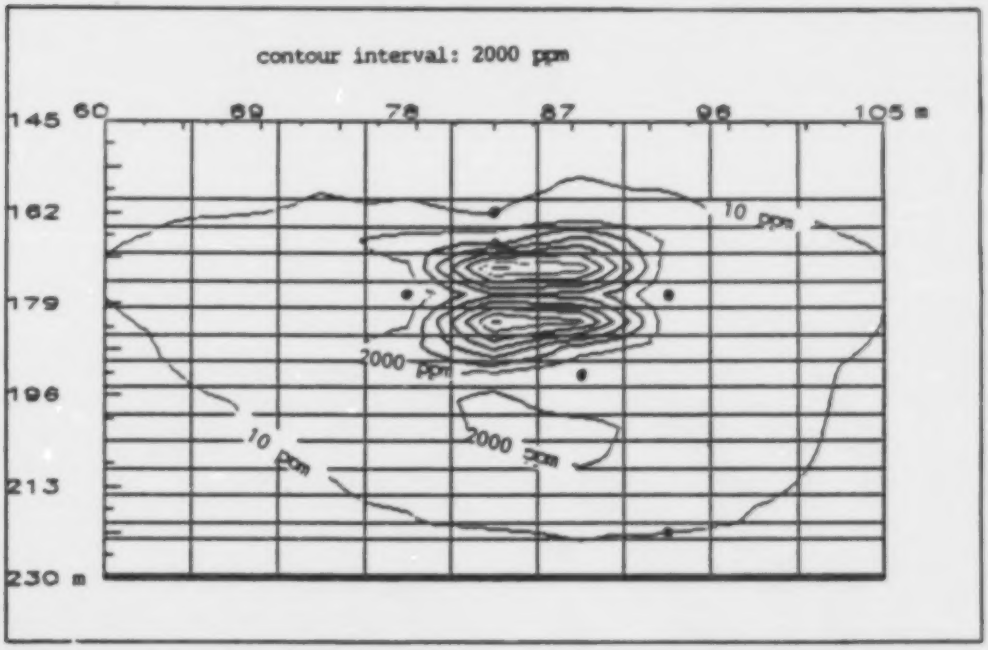

Figure 6: Pollutant concentration ten days after the beginning of the pumping test in accordance with concept I

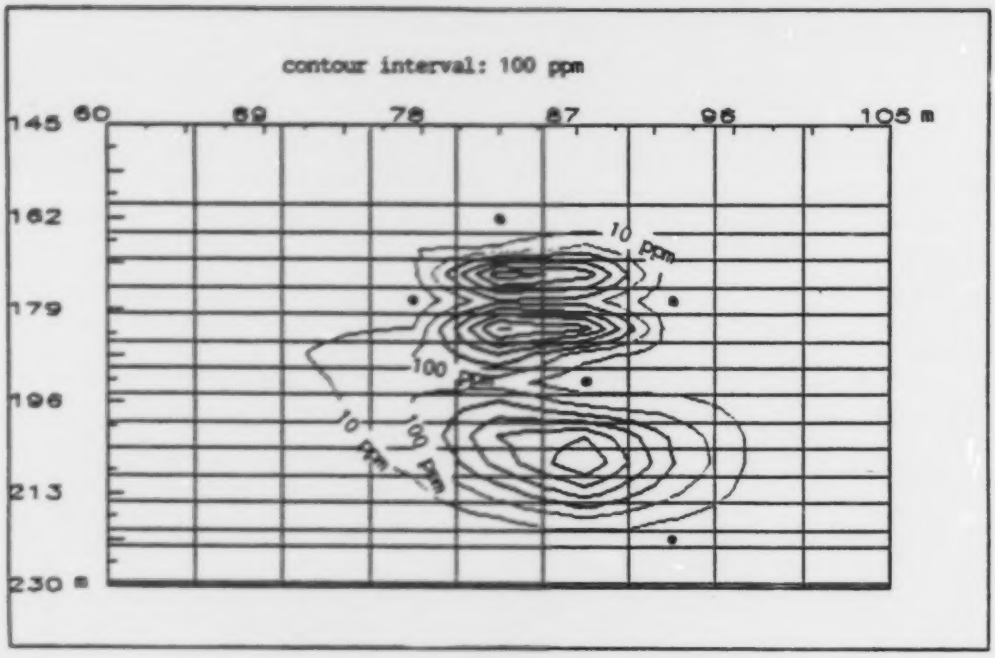

Figure 7: Pollutant concentration thirty days after the beginning of the pumping test for decontamination concept I

Decontamination concept II:

For remediation of the contaminated aquifer on the basis of concept II (three wells), the scheme presented in figure 8 can be applied. Ten days after the initiation of pumpings, toluene concentrations considerably higher than those for decontamination by concept I are still present. At the same time, however, the existing pollution zone is obviously not subdivided, but rather purged uniformly. Twenty days later, that is, at a time when only a very low concentration of toluene still prevails with concept I, considerably higher concentrations of toluene are still present (compare figure 7 and 9) with concept II. Nevertheless, it is obvious here, too, that the removal of toluene from the ground water proceeds decidedly more uniformly. Thirty days later, that is, after a total of seventy days after the beginning of the pumping, no toluene was present in the ground water with decontamination concept I, whereas a small residual quantity is still present with concept II (see figure 10); this residue is completely eliminated only after a further period of thirty days.

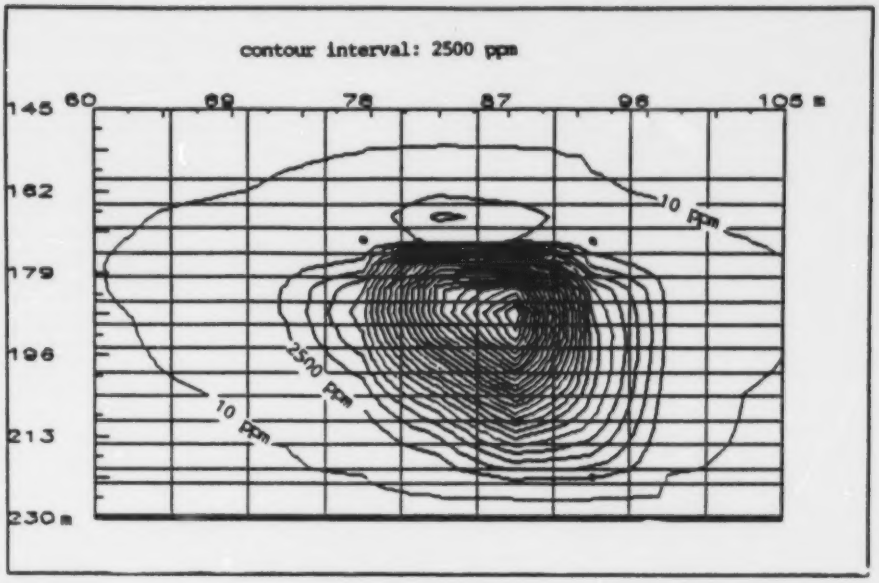

Figure 8: Pollutant concentration ten days after the beginning of the pumping test for decontamination concept II

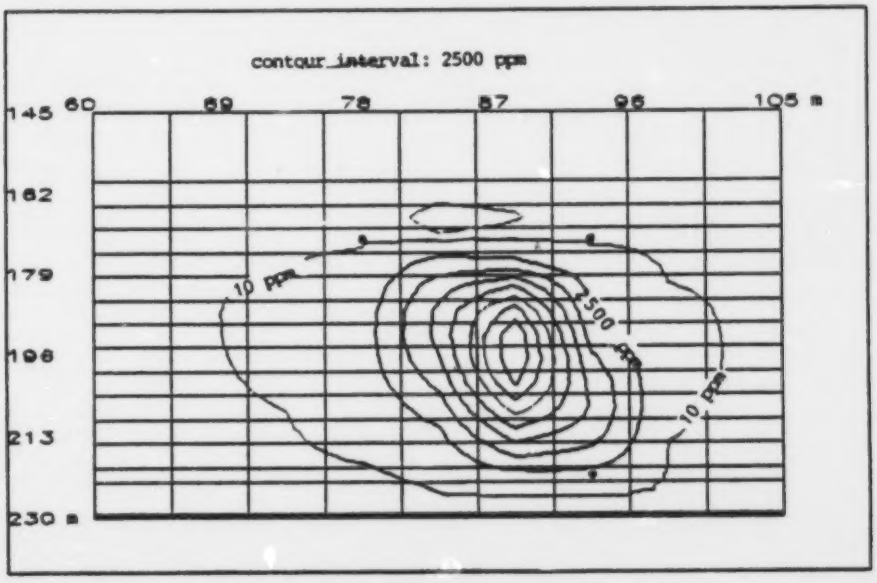

Figure 9: Pollutant concentration thirty days after the beginning of the pumping test for decontamination concept II

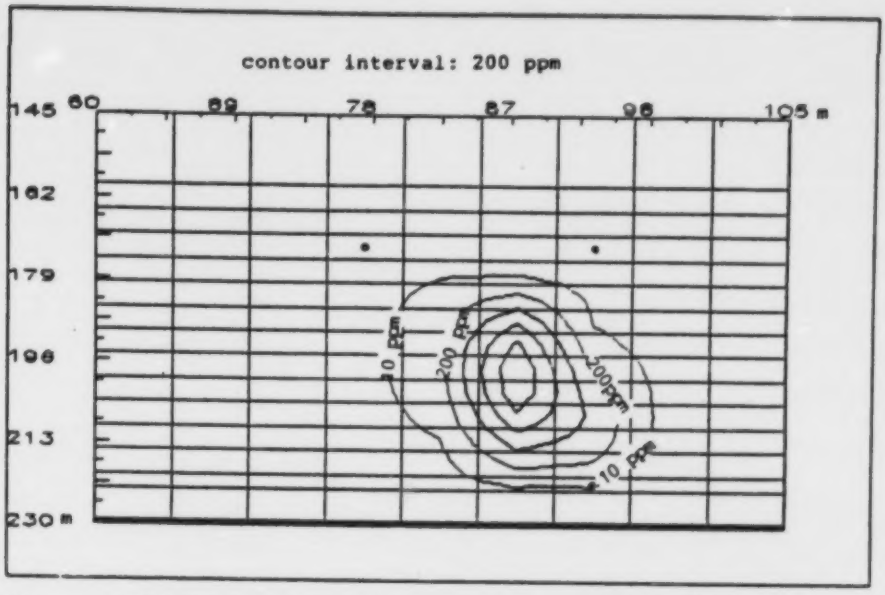

Figure 10: Pollutant concentration seventy days after the beginning of the pumping test for decontamination concept II

The results for decontamination concept II can be summarized as follows: After 100 days, the removal of the toluene is complete, and the decontamination of the originally polluted ground water is thus successful. A comparison with decontamination concept I indicates a time difference of 30 days for successful remediation. However, only two supplementary wells are necessary for concept II, whereas concept I requires four additional wells. Moreover, concept II obviously results in a considerably more uniform decrease in the pollutant concentration, whereas with concept I the existing pollution zone is subdivided into several smaller concentration zones, which are then eliminated in succession. In a heterogeneous aquifer the disintegration of the contaminated zone could be the cause for an ineffective remediation of the pollutant.

Conclusions

A multiphase flow model has been introduced with the aim of treating hydrogeological problems of multiphase migration. The programme, which has been developed in the oil and gas industry, is capable of simulating the simultaneous flow of water, a hydrocarbon phase, and a gas phase. Gravitational effects resulting from the difference in density among the phases involved in the flow, as well as capillary effects, are thereby taken into account.

With the use of a practical case as the analysis of ground water pollution by a toluene spill has been demonstrated by applying a 2-phase flow model. The propagation of the toluene was first analyzed by taking the flow velocity of

the ground water and the buoyancy force of the less dense toluene into consideration. Subsequently, two concepts for decontamination were proposed, compared, and appraised. One decontamination concept provides for drilling a pattern of four wells for the purpose, whereas only two additional wells in line are drilled, and one existing well is utilized with the other concept. It has been shown that the remediation concept involving two supplementary wells and the existing well results in complete decontamination of the ground water originally polluted with toluene after one hundred days. This approach requires a decontamination period which exceeds that for the other remediation concept by thirty days; on the basis of the model calculations, however, the extraction of the polluted ground water by pumping evidently proceeds considerably more homogeneously than that with concept I.

On the basis of the example presented, the principal applicability of the proposed multiphase simulation programme in the field of hydrogeology is evident. Many problems of environmental pollution involve processes of multiphase flow which cannot be correctly treated with the use of conventional single-phase programmes for hydraulic transport. The consideration of viscous and capillary driving forces, as well as gravitational segregation of several phases is feasible only with the application of a multiphase simulation programme.

Acknowledgements

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MONITORING IN THE VICINITY OF OIL AND GAS PLATFORMS: ENVIRONMENTAL STATUS IN THE NORWEGIAN SECTOR IN 1987-1989.

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Introduction

It is a widely held view that the impact of oil activities on the benthic fauna in the North Sea extends only to a 1 km radius from the installation, (1). However, data reported to the Norwegian State Pollution Control Authority (Statens forurensningstilsyn, SFT) as part of the obligatory monitoring undertaken by oil companies within the Norwegian sector suggested that effects could be measured as far out as 5 km from one platform, Statfjord C (2). Much controversy was generated by presentation of this data with the counter-claim being made that the effects observed were merely due to natural variations and were not due to oil-related activities. Recently, Gray et al (3) have shown conclusively that effects of oil-related activities on the benthic fauna around the oldest oilfield in the North Sea, Ekofisk, in 1987 can be found out to a 3 km radius from the platform. This is despite the fact that at Ekofisk up to 1987 much

less oil had been discharged than at Statfjord, (see Table 1).

SFT has the responsibility of safeguarding the marine environment from unnecessary pollution and can impose regulations on oil companies if the environmental effects warrant such action. It is clearly necessary that any impositions or restrictions of activities are based on sound analyses of the data reported. The reporting procedures themseves have been analysed in detail and a set of guidelines developed by Norway was adopted at the Paris Commission. The guidelines have been used for three years and this paper reports on the experience gained and on further evidence that the effects of oil activities on the benthic fauna confirm the suggestions put forward by Reiersen et al. (2).

Methods

Monitoring of the conditions around oil and gas platforms in the Norwegian sector of the North Sea is obligatory, with annual chemical monitoring and biological surveys conducted every 3 years (6 years for gas platforms). The data from the 1987-1989 reports (Table 1 shows the fields) allows us to assess general characteristics over several fields rather than extracting data for single areas. Gray et al (3) identified a number of species which were suggested as being highly sensitive to oil and/or a tracer of oil-based drilling muds, the barium content of the sediment, (see (2) for correlations between total hydrocarnon content of sediment and barium content). In order to test the hypothesis that abundances of these species were responding to oil related activities abundances were plotted against the total hydrocarbon concentration, THC and barium content for fields other than Ekofisk. Zero abundance values, i.e. where the species is not present in a sample, were excluded from the analyses.

In order to assess the statistical significance of changes in abundance the oil (THC) and barium values were divided into arbitrary logarithmic classes and an analysis of variance was performed on the $\log_{10}$ transformed abundances. In the following text significant refers to statistical significance as tested by the analysis of variance.

Results

Table 1 shows the data on the discharges of drill cuttings and oil up to 1989. For most fields there has been a marked decrease in the amounts of oil and cuttings discharged inn the period 1986-1989 despite the fact that the number of holes drilled has increased in the same period.

TABLE 1

Discharges of oil contaminated drill cuttings from selected platforms in the Norwegian sector of the North Sea from 1983 to 1989 (tons).

Platform	Year	No. wells	Discharges Cuttings	Oil
EKOFISK	83-85	7	903	129
	86	0	0	0
	87	2	1.120	39
	88	9	3.364	286
	89	8	2.768	185
STATFJORD A	83-85	16	5.203	2.243
	86	1	1.199	196
	87-89	0	0	0
STATFJORD B	83-85	20	13.066	2.520
	86	5	3.166	305
	87-88	0	0	0
	89	1	432	26
STATFJORD C	83-85	12	10.008	1.239
	86	11	8.839	876
	87	7	4.954	487
	88	2	2.383	230
	89	3	1.361	115
VALHALL	83-85	18	9.016	887
	86	7	1.854	134
	87	3	224	13
	88	5	2.483	157
	89	5	1.543	82
ULA	-87	0	0	0
	88	3	1.323	120
	89	6	1.313	96
OSEBERG	-85	1	521	61
	86	6	3.776	416
	87	4	1.952	204
	88	1	281	19
	89	4	2.495	223
TOTAL NORWAY	83-85	59	>41.000	8.268
	86	30	18.988	2.030
	87	26	13.777	1.256
	88	37	19.486	1.705
	89	43*	12.562	953

* For three wells all the cuttings were taken ashore.

Table 2 shows the concentrations of THC measured in the sediment at selected fields. The data show that the area affected is largest where discharges are highest, (Statfjord and Valhall). Table 2 shows clearly that background levels for the Norwegian sector of the North Sea are in the range 2-5 ppm and is even independent of the analysis method used. Values that are above 10 ppm are judged, by the laboratories analysing the hydrocarbon data, to be significantly contaminated. Background values for barium content were more difficult to obtain but were between 100-200 ppm.

TABLE 2

Concentrations of total hydrocarbons (THC) at outer sediment stations around selected Norwegian oil fields in the North Sea (mg pr. kg dry weight).

FIELD		YEAR									
	Distance (m)										
STATFJORD		1979	1980	1981	1982	1984	1985	1986	1987	1988	1989
A	2500#	15.3	16.3	12.3	10.2	30.1	31.4	45.8	58.9	18.2	41.9
	5000	-	<1.0	4.6	3.2	21.2	18.3	22.2	36.8	15.5	9.7
	7000	-	-	-	-	-	-	-	41.7	-	-
	10000	1.2	2.0	0.8	2.0	-	-	-	-	7.5	-
	15000	-	-	-	-	-	-	-	-	7.7	-
B	2500#			1.0	3.3	17.5	7.9	27.6	30.0	19.5	13.6
	5000			-	1.7	9.4	21.6	13.6	8.6	9.8	5.8
	7000			-	-	-	-	-	13.8	-	-
	12000			-	-	-	-	-	28.5	14.2	-
	15000			-	-	-	-	-	-	10.5	-
C	2500#			<1.0	1.4	5.5	-	51.8	86.6	17.0	28.8
	5000			-	<1.0	3.5	-	23.7	8.5	17.0	6.6
	7000			-	-	-	-	1.6	13.7	-	-
	10000								-	3.2	5.0
	15000								-	2.8	-

VALHALL	1983*	1984*	1985*	1986*	1987*	1987	1988	1989
2000	15.1	27.0	37.0	78.1	67.5	85.8	78.8	65.0
3000	-	-	13.0	26.0	-	-	-	-
4000	-	-	-	-	8.0	10.0	30.3	14.0
5000	-	-	-	13.8	-	-	-	-
6000	3.0	4.0	5.7	-	8.8	11.2	13.3	7.0
10000	-	-	-	6.5	4.7	5.9	-	5.0
15000			-	-	-	-	13.5	5.9

ULA	1984	1987	1988	1989
1000	4.0	6.1	13.9	8.9
2000	3.0	5.6	4.6	5.9
4000	4.0	-	-	3.7
6000	3.0	4.2	3.7	3.2

Before 1984 2000m. * mg pr. kg wet weight.

Tables 1 and 2 also show that once discharge declines so does THC at the outermost stations. For example at Statfjord A at 5000m values decline dramatically within one year from 1987 and from 1986 at B. For Valhall from 2000m and further distant THC values decline from 1988.

The data for the species were found to fall into distinct patterns. Fig 1. shows data for the bivalve Abra (cf prismatica).

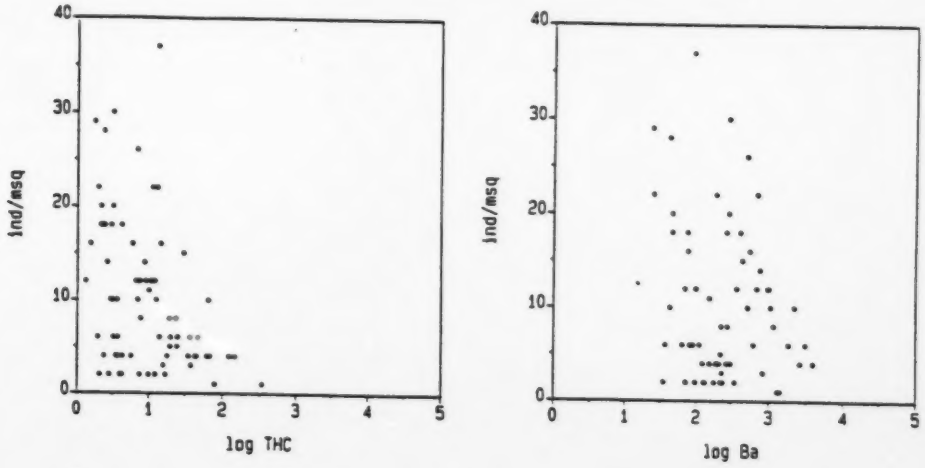

Fig. 1. Abundances of Abra cf prismatica at Valhall, Gullfaks, Oseberg and Ula oilfields, N.Sea. a) total hydrocarbon content (THC) of sediment, ppm
b) barium content of sediment, ppm.

Fig 1 (a) shows that there is a gradual decline in abundance starting at a Log_{10} THC level of 1.2 (15.84 ppm). There is a statistically significant difference between abundances at THC concentrations between 37 and 100 ppm and below 15 ppm. No Abra were found at concentrations higher than 400 ppm. Abra showed a similar gradual decline in numbers with barium content (fig 1 b) beginning at concentrations over 200 ppm, but only at concentrations above 700 ppm were the abundances significantly different from those at background level. An almost identical pattern occurs for the crustacean Eudorellopsis deformis (Fig 2) with a reduction in abundance beginning at 10 ppm THC (2 a), but due to high variance within classes the changes are not statistically significant. A dramatic and statistically significant increase in abundance occurs at barium levels over 250

ppm and a significant decrease again over 2000 ppm.

The polychaete Goniada maculata shows a slightly different pattern (fig 3 a) with first a significant increase in abundance from background THC levels and then a significant decrease in abundance over 100 ppm THC. G. maculata shows a similar response to barium as to THC (fig 3 b) with a significant increase in abundance from background levels of barium (300 ppm) up to 1000 ppm barium followed by a decrease in abundance.

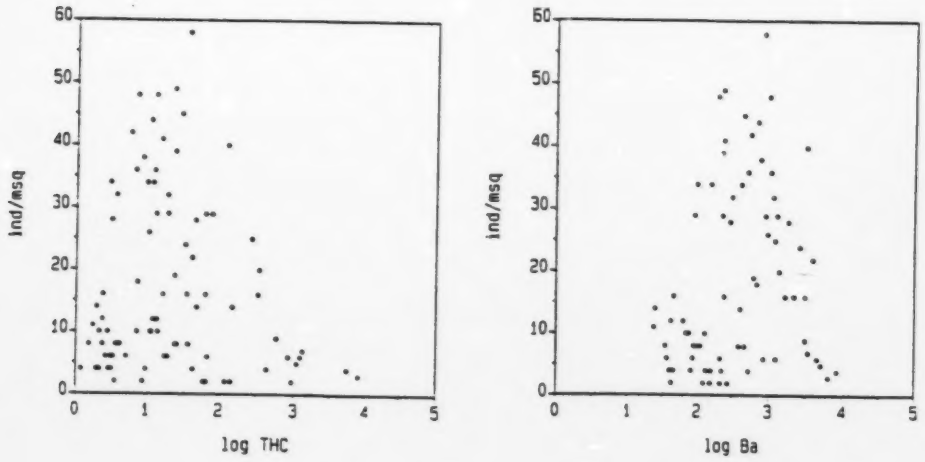

Fig. 2. Abundances og Goniada maculata at Valhall, Gullfaks, Oseberg and Ula oilfields, N. Sea. a) total hydrocarbon content of sediment, ppm.
b) barium content of sediment, ppm.

Nephthys longosetosa (not shown) shows a closely similar pattern to G.maculata with maximum abundances at 10 ppm THC. A decline in abundance occurs at THC concentrations above 10 ppm. For barium N. longosetosa shows maximal abundances at 1000 ppm, and a steep decline in abundance with increasing barium concentrations. The maximal abundance at 1000 ppm barium is significantly different from abundances at higher and lower barium content.

A species that has often been suggested shows higher abundance with organic enrichment is the polychaete Chaetozone setosa (4 and 5). Fig 3 shows with this species there is a large increase in abundance at THC

concentrations above 10 ppm but there is no decline in abundance at higher concentrations as with Abra and G. maculata. Abundances over THC concentrations of 700 ppm are significantly different from those below 10 ppm. The response to barium is similar to that to THC with an increase in abundance at concentrations over 500 ppm and maximum abundances at concentrations over 6000 ppm with no decline in numbers. The increase in abundance is however, gradual and variances within barium classes are high so that there is no statistically significant difference between abundances at highest and lowest barium content.

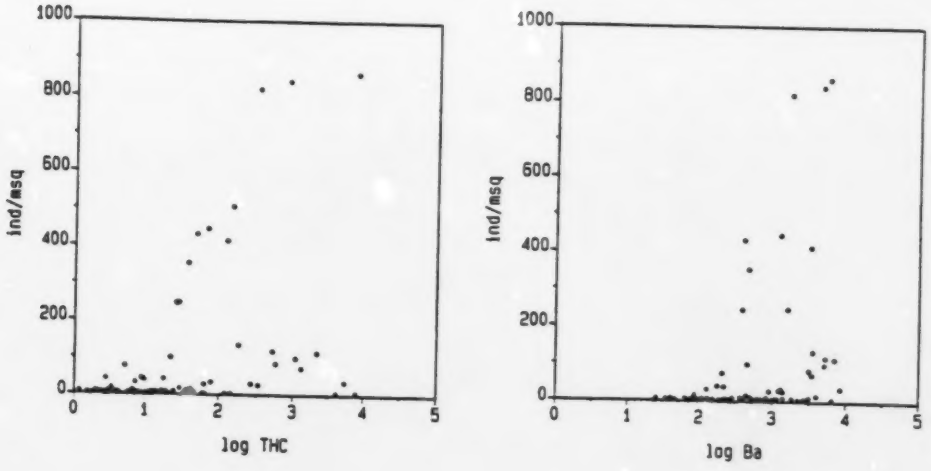

Fig. 3 Abundances of Chaetozone setosa at Valhall, Gullfaks, Oseberg and Ula oilfields, N.Sea. a) total hydrocarbon content (THC) of sediment, ppm
b) barium content of sediment, ppm

Another commonly recommended indicator species for organic enrichment is the polychaete Capitella capitata. Here C. capitata showed a large increase in abundance beginning only at over 300 ppm THC and rising continuously with maximal abundances occurring at THC concentrations of almost 10,000 ppm. Abundances at the highest THC concentration are significantly different from at all other concentrations. So far from being useful as an indicator species C. capitata is merely an indicator of grossly polluted conditions.

The polychaete Aonides pauchibranchiata shows a decrease in abundance from a THC of 10 ppm with total absence over 100 ppm THC but shows no clear response to barium with neither an increase at concentrations over backgound nor a decrease at concentrations of up to 1000 ppm. Due to high variance within classes (THC and barium) there are no statistically significant differences between highest and lowest abundance classes.

Discussion

The most obvious pattern to emerge from figs 1-3 is that for three species Abra, Eudorellopsis, Nephtys and Aonides there is a maximal abundance at approximately 10 ppm. As THC concentrations increase over 10ppm these species show declines in abundance and very few individuals are found at over 100 ppm. With Goniada and Nephtys there is an increase in abundance from backrground THC levels to 10-100 ppm and thereafter a decline.

Chaetozone and Capitella show increases in abundance with increased THC content, but Chaetozone begins to increase in abundance at 30 ppm whereas for Capitella the increase begins above 100 ppm.

For barium a conservative lower limit for effects for all species is 500 ppm. Whether or not the response to THC and barium are independent or simply represent responses to the same gradient remains to be studied. Only A. pauchibranchiata shows a response to THC which is different to the response to barium.

The lowest threshold of response from field observations is 10 ppm THC and for the studied fields the distance from the platforms that such concentrations are equivalent to (Table 2) is as far as 7000-12000m (Statfjord) and 6000-15000m (Valhall). In the absence of any measures to control dischargess of oil then one can expect significant changes in the species composition of benthic communities out to 10000m and perhaps beyond. Thus the suggestion in Reiersen et al (2), that effects of oil-related activities at the Stafjord C field out to 5000m could be related to such activities, which was hotly disputed at the time, appears to be confirmed from the present data.

New regulations for discharge of oil contaminated cuttings were introduced in 1988 by SFT. The operators were asked to reduce the discharge of oil-contaminated cuttings. The effect of this change in policy can be seen both both in the reduction of totals tons discharged and on concentrations measured in the sediment at the outermost stations. Despite the increased number of wells drilled in 1989 discharges were reduced compared with 1988, (Table 2).

From 1st January 1991 the discharge of oil contaminated cuttings will be banned in the Norwegian sector of the North Sea. Exceptions will be allowed for safety and geological reasons and the discharge limit will be 10 gm kg^{-1} compared with today's limit of 100 gm kg^{-1}. For existing fields there will be a transitionary period up to 1st January 1993, (60 gm kg^{-1}). It is unlikely, therefore, that the effects on the fauna at levels down to 10 ppm found with the use of new analysis techniques (3) and in this paper, will extend out to 10000m or beyond.

At the Calgary Drilling Wastes Conference in 1988 a set of guidelines drawn up by SFT for use in the Norwegian sector were presented. In spring 1988 the guidelines were adopted by the Paris Commission for general application. Prior to the guidelines being adopted within Norway the mandatory monitoring programmes were done by independent consultant companies and universities which used methods most convenient to themselves and with no compatibility between methods. In Calgary we presented an evaluation of sources of variation in the monitoring programmes (2) which clearly showed that such variations did not reflect differences between fields but was largely due to methodological differences. Thus it was difficult to compare trends in contamination over time.

The introduction of the guidelines has led to standardisation of methods for sampling, extraction, storeage, analyses, reporting and quality assurance such that data are much more reliable and it is now possible to make comparisons between surveys both around one field and between different fields.

The monitoring data are presented in a report and in addition the raw data has to be presented on a computer diskette, which simplifies SFT's overall assessment and

allows statistical analyses to be done rapidly, e.g. this report.

The methods and procedures adopted by the Paris Commission Guidelines are applicable to many point source monitoring situations such as industrial and sewage discharges. By suitable adjustment of the sampling stations the Guidelines can serve in a wider control function.

The Norwegian experience can be summarised as the imposition of tighter guidelines for monitoring has led to more reliable data on environmental conditions around oilfields. The, now, high quality of the data obtained by the oil companies has allowed new techniques of biological effects assessment to be applied. These techniques show effects at THC levels down to 10 ppm. This in turn has led to tightening of the legislation on discharge from oil platforms in the Norwegian sector. With imposition of the new legislation rapid improvement of environmental conditions has been observed at stations distant from the platforms. Thus rather than a conflict between environmental control authorities and the oil companies, a mutually beneficial state has been reached wher the oil companies conduct state-of-the-art monitoring which the SFT then can ensure that unacceptable environmental damage will not occur.

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NATURE, OCCURRENCE AND REMEDIATION OF GROUNDWATER CONTAMINATION AT ALBERTA SOUR GAS PLANTS

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Abstract

A study of subsurface contaminant monitoring and remediation data from 55 Alberta sour gas plants was undertaken through sponsorship of the Canadian Petroleum Association and Environment Canada. Data for the study consisted of monitoring reports collected by Alberta Environment pursuant to the Alberta Clean Water Act. Study objectives were to determine the most frequently occurring groundwater contamination situations, classify them by contaminant type, source, and geologic host, and evaluate the level of remediation technology being applied in the province.

Some form of impact on groundwater quality was detected at all but one of the gas plants reviewed. In the majority of cases contamination was locally restricted and did not appear to have moved off-site, however data did not allow an evaluation of the seriousness of contamination situations. Process water ponds were a source of contamination at over two thirds of the plants. Other important sources of contamination were process areas, on-site landfills, and sulphur block. The most common contaminants were chlorides, and dissolved organics. Free phase condensate was present at several facilities. The majority of contaminated saturated horizons were of moderate hydraulic conductivity (10^{-5} to 10^{-8} m/s), typically sandy till deposits common in Alberta. Groundwater contamination situations in many cases relate directly to plant waste management practices, past and present.

Currently, Alberta Environment data indicate that groundwater remediation systems are operating or are being installed at three plants. All are pump and treat schemes, and deep well injection is the favoured method for disposal of recovered contaminated groundwater.

Introduction

Much of the natural gas produced in the province of Alberta is associated with varying concentrations of hydrogen sulphide gas (H_2S). Sour gas plants remove hydrogen sulphide from the natural gas stream through a variety of processes, producing elemental sulphur, sales gas, and hydrocarbon liquids. There are

presently more than one hundred and fifty sour gas plants operating in Alberta, ranging in capacity from as little as 11,000 m^3/day to more than 17,000,000 m^3/day of raw gas (Oilweek, 1987). The oldest facilities have been in operation since the early 1950's, and several new complexes are now in the design stage. This fact is reflected in the wide range of process types and plant designs present in Alberta.

Due to the nature of the processes involved in sour gas processing and the wastes and by-products produced, sour gas plants pose a potential threat to local groundwater quality. Substances which may impact groundwater quality at sour gas plants include free phase and dissolved hydrocarbon products (such as condensate), process water and chemicals (such as amines, glycols, and degradation products), produced waters (brines, saline and brackish water), solid wastes and sludges, seepage waters, surface runoff (from sulphur blocks, process and loading areas), and active or abandoned landfills on site.

Recognizing the need to protect groundwater from deleterious effects resulting from plant activities, the Canadian Petroleum Association, in conjunction with Environment Canada, sponsored a study into subsurface contamination and remediation at Alberta sour gas plants. The main objectives of the study, on which this paper is based, were the compilation of knowledge of sour gas plant related subsurface contamination situations, the determination of the most frequently occurring contaminant situations present at these facilities, and a review of the groundwater remediation projects currently underway in Alberta. Subsequent phases of this work are to include design and implementation of one or more remediation technology demonstration projects at Alberta sour gas plants.

Available Data

The study was based on data provided by Alberta Environment, and consisted of documents submitted to the Standards and Approvals Division by plant operators pursuant to the Alberta Clean Water Act. In all, information was obtained for 54 Class B sulphur-recovering sour gas plants.

The quality and completeness of information contained in the reports were quite variable. In some cases basic hydrogeological data such as groundwater flow directions, geological logs and piezometer locations, were not available. Of the 54 plants considered, sufficient data for adequate appraisal of subsurface contamination situations were available for 32. Information from 13 of the remaining plants allowed partial contamination assessment only.

The variability in data reporting reflects to a large extent the lack of detailed groundwater monitoring and data reporting guidelines for sour gas plants in Alberta. Alberta Environment is presently working on a new set of guidelines for groundwater monitoring at industrial and waste disposal facilities in the province, although at this time it is uncertain when these will be available.

Methodology

Assessment of Contamination

The available data for each gas plant were reviewed and where possible groundwater

contamination situations identified. No assessment of the seriousness of the various contamination situations was undertaken, as in the majority of cases, insufficient data were available for this task. "Seriousness" of a given contamination situation, or in other words the perceived need for abatement or remediation, will depend on a number of factors including:

- plant location with respect to other groundwater users, water courses, population centres, and areas of especial environmental concern;
- nature, types and concentrations of contaminants;
- rates of contaminant transport;
- analysis of the fate of contaminants, risk assessment;
- regulatory guidelines and considerations.

In the majority of cases, these types of data were not available in the reports provided by Alberta Environment for this study. Current guidelines do not specify provision of evaluations of the fate of contaminants by operators.

Classification of Findings

Wherever sufficient data were available, the source, type and geologic host of contamination were determined for each contamination situation. From these three pieces of information Contamination Situation Classifications, or CSC's, were assigned, according to the categories shown in Table 1. For the purposes of this study, a contamination situation is defined as: "an occurrence of subsurface contamination at a given sour gas plant, distinct from other occurrences at the same plant in that it has a different source, or the contamination is found in a different hydrogeological unit)".

TABLE 1
CONTAMINANT SITUATION CLASSIFICATION SYSTEM

SOURCE	TYPE	ZONE
1. Process Area	A. Free Hydrocarbon	I. Unsaturated Zone
2. Sulphur Block	B. Dissolved Organic	soils, surficial
3. Surface Runoff	C. Main Ions	material, bedrock
4. Process/Produced	D. Sulphur Products	
Water Ponds	E. Metals	Saturated Zone
5. Product Loading	F. Other	II. High Hydr. Cond
Facility	(e.g. TKN,	K > 10E-5 m/s
6. Landfill	priority pollu-	
7. Injection well	tants, etc.)	III. Moderate K
8. Other		10E-5 > K > 10E-8 m/
9. Unknown		
		IV. Low K
		K < 10E-8 m/s

It is possible for several CSC's to exist at a given plant. For example, a facility may have a small sulphate plume in the uppermost groundwater bearing zone (a sandy clay till layer of low hydraulic conductivity) extending from the sulphur block area, and a larger plume consisting of high concentrations of chlorides and dissolved organics (high TOC and sulfolane identified in trace organics scan) originating from the evaporation pond, in another part of the same uppermost aquifer, but also found in a deeper bedrock aquifer of moderate hydraulic conductivity.

Consulting Table 1, three CSC's could be developed for this scenario:

2 D IV:	sulphur products from sulphur block in low K zone;
4 BC IV:	ions and dissolved organics from evaporation pond in a low K zone;
4 BC III:	ions and dissolved organics from evaporation pond in a moderate K zone.

Once so classified, contamination situations at various gas plants were compared and grouped with the assistance of a computerized database system developed for the study. In this way, common trends in subsurface contamination at Alberta sour gas plants were identified.

There exists in the data a slight correlation between the completeness of the monitoring data available for a given facility and the number of contamination situations identified there. Small monitoring networks which did not cover all areas of possible contamination may have failed to detect all groundwater contamination present. In light of this, the data presented as a result of this review should not be taken solely as an indication of the relative care with which plants have controlled and disposed of plant wastes and by-products, but also of the relative degree to which they have attempted to assess the subsurface contamination present at their sites.

Groundwater Contamination

Of the 45 plants for which information allowed assessment of the presence of groundwater contamination, only one showed no signs of impact of plant activities on groundwater quality. Table 2 shows the number of plants at which one or more CSC's were determined. Two or more contamination situations were identified at 36 of the 45 plants.

Sources of Contamination

There were sufficient data available at 42 plants to determine sources of groundwater contamination. Table 3 shows the number of plants with at least one contamination situation originating from each of the source categories. Thirty-three of the 42 plants (78.5%) had at least one contamination situation originating from the process water/evaporation pond. Other common sources of groundwater contamination were process areas and on-site landfills. The sulphur block area was also identified as a frequent source of contamination. Other sources of contamination which were identified included general surface runoff, injection wells on-site, and product loading areas.

TABLE 2
NUMBER OF CONTAMINATION SITUATIONS DETERMINED AT GAS PLANTS
(Total of 45 Surveyed)

Number of CSC's per Plant	Number of Plants	Cumulative Number of Plants
4 or more	10	10
3	12	22
2	14	36
1	8	44
none	1	45

TABLE 3
SOURCES OF GROUNDWATER CONTAMINATION
Number of Plants with at Least one Contamination Situation Originating from the Given Source
(Total of 42 Surveyed)

Source	Number of Plants	Percentage of Plants
Ponds	33	78.6
Process Area	23	54.8
Landfill	20	47.6
Sulphur Block	16	38.1

Types of Contamination

There were sufficient data available at 44 plants to determine the types of contaminants in groundwater. Main ions and dissolved organics were the most commonly identified groundwater contaminants. Impact on groundwater quality by sulphur products, notably sulphate and in some cases acid seepage waters, were identified at 17 of the 45 plants.

Free phase condensate contamination was identified at five plants. Although this number represents only about one-tenth of the plants surveyed, the relative concern attached to this type of contamination makes it of particular interest. Free phase hydrocarbon contamination is difficult and expensive to remediate, and very low levels of hydrocarbon render water unfit for human or animal consumption. Table 4 shows the number of plants with at least one contamination situation involving each of the six major contaminant groups.

Contaminants in groundwater often occurred in combinations. For instance a particular plume emanating from an evaporation pond may have contained main ions such as chloride and sulphate, dissolved organics, and metals. All such combinations were recorded during the data review phase. Table 5 shows a breakdown of the occurrence of the more common combinations. Among gas plants in the study set, half had at least one situation where groundwater was contaminated by dissolved organics and main ions.

TABLE 4
TYPES OF GROUNDWATER CONTAMINANTS
Number of Plants where the Indicated Contaminant type was Identified at Least Once (Total of 44 Surveyed)

Type	Number of Plants	Percentage of Plants
Main Ions	42	93.3
Dissolved Organics	41	91.9
Sulphur Products	17	37.8
Free Hydrocarbon	5	11.1
Metals	3	6.7

TABLE 5
CONTAMINANT COMBINATIONS
Number of Plants where the Indicated Combinations were Identified at Least Once

Combination	Number of Plants
Main Ions + Diss. Organics	22
Main Ions + Diss. Org. + Other	19
Sulphur Products Only	15
Main Ions Only	13

It must be noted that findings are affected by the analytical schedules which the various operators chose to run on their groundwater samples. If more comprehensive analysis of groundwater quality had been done, additional contaminant types may have been identified.

Zone of Contamination

Data with which the location of groundwater contamination could be determined were scarcest in the reports provided by Alberta Environment for this study. All of the 13 plants for which only partial CSC's could be generated lacked sufficient data to classify the zone of contamination. In most instances, borehole logs or piezometer construction details were not available, making it very difficult to determine which groundwater-bearing zone was being sampled. As a result, the nature and hydraulic properties of the geologic host of groundwater contamination could be determined at only 32 of the 54 plants in the study group.

Zones were classified according to their average hydraulic conductivity, to provide some indication of the ability of contamination to migrate away from source. Unsaturated zone (soil) contamination was provided a separate classification (Type I). Table 6 shows the number of plants at which contamination occurs in each of the three saturated zone classifications. The majority of groundwater contamination situations at Alberta sour gas plants seem to occur in zones of moderate hydraulic conductivity (10E-5 < K < 10E-8 m/s), represented by such materials as inter-till clayey sand and silt layers and fractured bedrock common in Alberta.

TABLE 6
ZONES OF CONTAMINATION
Number of Plants with at Least One Contamination Situation Occurring in the Indicated Zone (Total of 32 Surveyed)

Zone	Hydraulic Conductivity Range (m/s)	Number of Plants
II	>10E-05	7
III	10E-05 - 10E-08	20
IV	<10E-08	6

Although directly related to the surficial geology of Alberta, this breakdown does serve to confirm that most groundwater bearing zones which are impacted by sour gas plant operations are not extremely hydraulically conductive. Twenty-six of 32 plants had contamination in groundwater bearing zones whose hydraulic conductivity was less than 10E-5 m/s. This helps to put the situation at Alberta sour gas plants into perspective. In the majority of cases, the estimated advective transport rates of groundwater contamination were not very high, however consideration must also be given to the influences of fracture permeability, contaminant-matrix interactions and the accuracy of hydraulic conductivity data provided in reports. Detailed analysis of contaminant transport rates at the various gas plants was beyond the scope of this study.

Discussion

The sources and types of groundwater contamination identified at Alberta sour gas plants in many cases relate directly to the waste management practices followed at the plants. Process water/retention ponds at plant sites may receive water which has been used in plant processes, surface runoff from process areas and sulphur storage blocks, produced brines, and miscellaneous waste-water. This water may contain elevated concentrations of dissolved salts, sulphate from sulphur block runoff, organic process chemicals and dissolved hydrocarbons.

Many of these impoundments, particularly at older plants, were excavated into surficial material and were either left unlined or were provided with compacted natural clay (till) liners. The results of this survey indicate that such ponds are the single most common source of deleterious impacts on groundwater quality at sour gas plants. Improvements in construction and lining of new and existing wastewater retention ponds are being implemented throughout the industry, and should help to reduce future problems.

On-site landfills were also identified as a common source of contaminants in groundwater. At many older gas plants, landfills have been used to dispose of a variety of wastes, including sulfinol filters, scrap, construction debris, sulphur, waste oil and condensate, amines and catalyst. Proper siting, construction, capping and abandonment of on-site landfills will also help to reduce impacts on groundwater.

The plants reviewed all engage in recovery of elemental sulphur, which is often stored on-site in large blocks to await shipment. Impacts on groundwater attributed to sulphur include elevated sulphate concentrations and acid water seepage. Although the data reviewed identified the sulphur block as a source of groundwater contamination at only 16 of 42 plants, it is likely that the actual number is much higher. At many of the plants reviewed, no monitoring points had been established down-gradient of sulphur storage areas. Whenever such monitoring wells were installed, impacts on groundwater quality were detected. It is recommended that groundwater monitoring down-gradient of sulphur storage areas be stipulated as a requirement in future Alberta Environment guidelines for sour gas plants.

A correlation was found in the data between the number of contamination situations occurring at a given plant, and the age of the plant. This is attributed in part to the longer periods available for contaminant introduction and migration at older plants, and is also seen as a function of improvements in waste management practices at newer plants.

Groundwater Remediation

Data Available

Information was obtained describing subsurface remediation programs at five sour gas plants in Alberta. Of these, two were primarily soil remediation operations (plant decommissionings), and three were groundwater remediation schemes currently installed at operating facilities. To date, no other data from remediation programs at sour gas plants has been submitted to Alberta Environment.

Case History

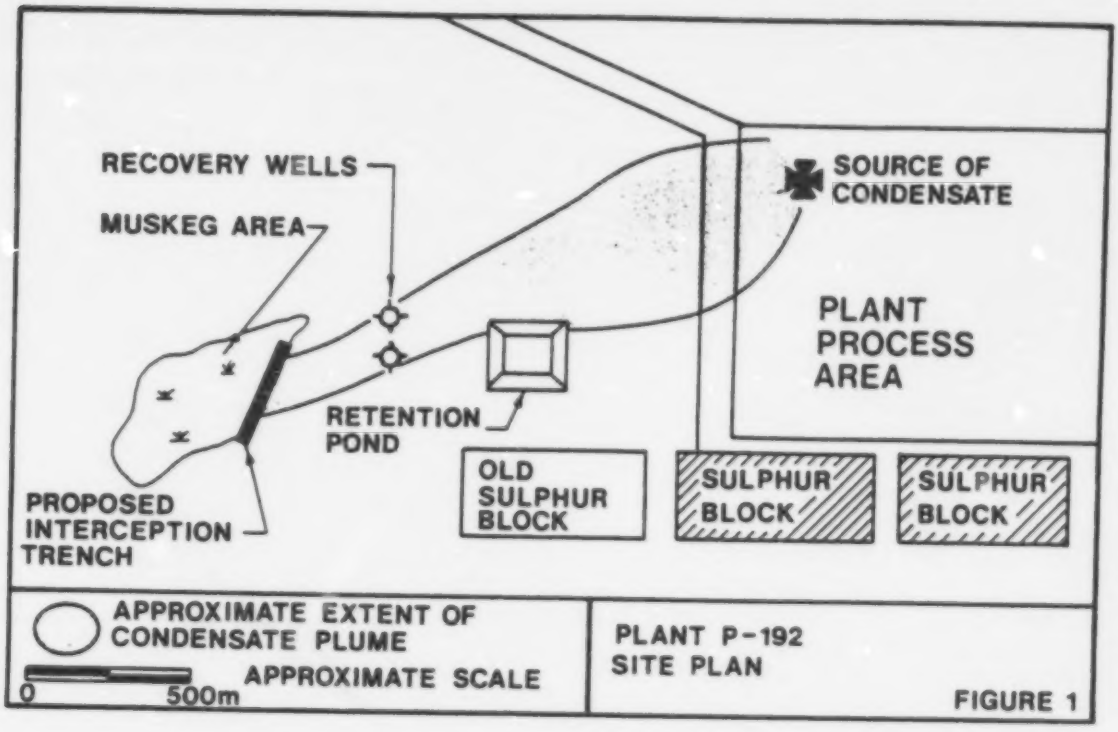
A groundwater remediation program at Plant P-192 was initiated by plant personnel in 1986, in response to discovery of a free-phase condensate plume downgradient of the plant site. During this year four 114 mm OD diameter wells were installed to recover condensate and contaminated groundwater originating from the process area and evaporation ponds. These attempts at using single conventional pumping wells to extract LNAPL met with very limited success.

Subsequently, a more detailed hydrogeological study of the plant site and surroundings was completed. This study refined understanding of groundwater flow patterns at the site and the distribution and properties of the various hydrogeologic units at the site, and accurately delineated the extent of the plume. The condensate plume was found to extend about 1.5 km downgradient of the plant, attaining apparent thicknesses of up to 1.5 m (Figure 1).

The new information indicated the need for an improved contaminant recovery system. At that time, the source of condensate was identified as a leaking buried condensate line in the plant process area. The leak was repaired, but may have been active for several years. Subsequently, all buried condensate lines in the plant area were replaced by overhead lines.

In 1989, five 130 mm test wells were placed downgradient of the plant, near the down-gradient edge of the condensate plume. These wells were tested to provide information on the hydrogeologic properties of the contaminated aquifer, which consists of interbedded fractured shale, siltstone and sandstone bedrock overlain by and in hydraulic connection with glacio-fluvial sands and gravels. The recovery wells have been fitted with dual pump systems designed expressly for the recovery of light non-aqueous phase liquids (LNAPL) from the groundwater surface. An integrated groundwater recovery, treatment and disposal program is now being designed and tested for implementation in 1991.An area of muskeg approximately 750 m down-gradient of the plant site was also found to have condensate contamination. An interception trench is planned for 1990/91 to contain the plume in this area.

The site characterization and remediation programs conducted at Plant P-192 were found to be some of the most thorough and advanced of all plants involved in the study.



Discussion

Subsurface remediation efforts at Alberta sour gas plants to date have included a variety of techniques. Where geologic conditions were suitable, large diameter passive collection systems have been used to recover free-phase hydrocarbon. Attempts to recover free phase condensate in more permeable aquifers using single well pumping schemes have, not unexpectedly, been relatively unsuccessful. Application of dual-pump scavenger-type systems to recover free phase condensate and groundwater separately is being considered at several facilities. Traditional pump and treat methods are being applied for the recovery of groundwater with dissolved contaminants, and the control of plume migration. Deep well injection is the favoured method for disposing of contaminated groundwater.

The number of plants at which remediation operations are known to be presently underway is relatively small. In many cases, remedial action has been deemed

unnecessary due to geologic conditions and relative isolation of plants, far from any nearby groundwater users, water courses or population centres. In some instances, remediation has been deemed impractical due to limitations of available technology. However, rapid advances in the understanding of processes governing contaminant migration in heterogeneous geologic media, and new developments in remedial technologies should improve our ability to remediate difficult sites. One consideration to date has undoubtedly been the relatively high cost of subsurface remediation and the fact that at present no regulations or guidelines are available for these operations in Alberta.

The need for clean-up must also be determined. Risk analysis and contaminant transport modelling techniques provide ways of assessing the likelihood of contamination impacting the public or the environment. Results of the risk analysis can then be provided to regulators to ensure a case-by-case assessment of the need for remediation at sour gas plants. Gas processing facilities in the province are found in such diverse locations, and represent such a wide range of hydrogeological and climatic conditions, that application of a single set of rigid criteria to determine the need for clean-up is not recommended. A case-by-case consideration of facilities would help to ensure the economical application of the limited resources. Operators could then direct available funds toward the most serious problems.

Once contaminated, aquifers are very difficult to remediate, and clean-up operations are expensive. Clearly, the best answer to groundwater contamination problems is to prevent the movement of contaminants into the groundwater. Good waste management practices are the cheapest and surest aquifer protection.

Conclusions

The most common sources of groundwater contamination at Alberta sour gas plants were process water ponds and on-site landfills. Dissolved organics and main ions were the most common contaminants, although free phase condensate LNAPL was present at several plants, and is seen as being of particular concern. Most contamination occurs in geologic horizons of relatively low hydraulic conductivity. In many instances, negative impacts on groundwater quality at sour gas plants can be linked to the waste management practices followed at the facility.

The number of Alberta sour gas plants at which remediation programs are underway is relatively small. It is recommended that industry and government consider jointly developing a set of guidelines for the design and implementation of remediation programs.

Disclaimer

The opinions expressed in this paper do not necessarily reflect those of the project sponsors, the Canadian Petroleum Association and Environment Canada.

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A NEW PIPELINE LEAK-LOCATING TECHNIQUE UTILIZING A NOVEL ODOURIZED TEST-FLUID (PATENT PENDING) AND TRAINED DOMESTIC DOGS.

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INTRODUCTION

Pipeline leaks continue to plague industries which construct, operate or move products through such facilities. The problem is compounded by the fact that many existing pipelines are nearing the end of their intended service and are therefore more susceptible to failure. Accordingly, the incidence of pipeline leaks has been increasing. For example, over the last eleven years, the incidence of leaks in Alberta alone has steadily risen from 421 in 1978 to 913 in 1988 (1). The economic penalties associated with such leaks can be particularly onerous, involving substantial product loss, line down time, fines resulting from regulatory non-compliance, and remediation of environmental impacts. Notwithstanding the direct economic penalties, there is growing public expectation for corporations to become more proactive in minimizing any environmental impacts resulting from their operations.

A review of the literature revealed that more than thirty different pipeline leak-detection systems are presently in use (2) but despite the plethora of available detection methods, many systems have distinct handicaps which limit their usefulness. Most techniques are limited by being prohibitively expensive, by their requirement for incorporation into a pipeline at the time of construction, or by having application to a relatively small range of pipeline diameters. Because of the lack of dependability of some of these methods, many pipeliners continue to locate leaks by cutting failed lines in half and hydrostatically pressure-testing both sections. Sections which subsequently fail the pressure test are halved again, and after numerous successive cuts and pressure tests, the leak is eventually located, often after substantial costs have been incurred due to labor, equipment-standby and lost production.

Another pipeline leak-detection technique in common use involves the injection of odourized air or hydrostatic test-fluid into leaking lines and attempting to detect the odourant at the soil surface above a leak. Traditionally, one of several thiols (mercaptans) is used as the odourant. Although this method has enjoyed some success (3,4), it has a number of

technical shortcomings. For example, when a thiol is used in an air-test, safety considerations usually limit pressure testing to approximately 700 kPa. Air-testing pipelines at higher pressure risks the safety of personnel, as well as substantial line damage which could result from localized line rupture or even catastrophic failure. These safety concerns clearly preclude the use of thiol-based air-tests on most pipelines because the majority of lines require testing at much higher pressures. Concerns also exist where thiols are used in the liquid phase. When thiols are introduced into hydrostatic test-fluid, they align strongly with the test-fluid water and consequently disperse underground within the aqueous phase. Accordingly, precise location of pipeline leaks is severely compromised when using either of these techniques.

Because of the limitations of available leak-detection technology, Esso Resources Canada Limited (ERCL) embarked on a research program to develop an effective, more precise odourant-based leak-detection system. A major focus of the research was to develop a test-fluid which could be injected into leaking pipelines and which, after leaking into the soil, would release an odourant which would migrate directly to the soil surface for detection. A critical technical challenge involved with the development of this fluid was to maintain minimum solubility of the odourant in other test-fluid constituents, while at the same time ensure the odourant would remain in phase during the procedure. This consideration was particularly important because, if the odourant came out of phase and rose to the top of a pipeline, then any test-fluid flowing from a leak on the bottom of a line would contain no odourant and therefore could not be accurately located.

STUDY OBJECTIVES

The objectives of the program were threefold:

a) To identify an odourant for incorporation into the leak-detection test-fluid having the following characteristics:

- strong, identifiable odour
- sufficiently high vapour pressure to migrate vertically through at least 2 m of soil (ie. good soil penetrability)
- relative non-solubility in water
- non-toxic when used in low concentrations
- relative non-reactivity with soil constituents, with pipeline materials, or with products transported in pipelines
- readily available
- readily identifiable by a portable detector;

b) To identify a detector that was portable, could operate in real time, and could detect the above-mentioned odourant at very low concentrations, and;

c) To evaluate the overall test-fluid / detector system under controlled conditions, and subsequently on actual pipeline leaks.

PRE-TRIAL CONSIDERATIONS

Prior to conducting field tests, preliminary work was undertaken to identify the optimal odourant, incorporate that odourant into a leak-detection test-fluid, and identify a detector capable of meeting the established study criteria. The following section describes that preliminary research effort.

Odourant Selection And Test-Fluid Considerations

A review of the literature was conducted in order to generate a short list of odourants which satisfied the criteria outlined above. As a result of this review, a number of odourant families were identified and appropriate representatives from each family were then evaluated.(As of this conference, the test-fluid chemistry has "patent pending" and "trade secret" status. Accordingly, the following section provides a "generalized" discussion of the work leading to development of the test-fluid: specific details of the chemistry will not be addressed.)

Figure 1 shows Candidate A has a human odour threshold equal to or less than most most other odourant candidates, and approximately one fifth the human detection threshold for hydrogen sulphide (a compound well known for its low detection threshold). The relative vapour pressures of the short-listed odourant candidates are compared in Figure 2. These data show that only Candidate B is appreciably more volatile than the prime Candidate A. Solubilities of the odourant candidates in water are summarized in Table 1. This table shows that the prime odourant candidate meets the solubility requirements stated above.

Analysis of the data presented in Figures 1 and 2, and in Table 1, indicate that odourant Candidate A (hereafter referred to as "the odourant") possesses the best overall complement of physical characteristics consistent with the requirements of the leak-detection procedure. In order to combat the tendency of the chosen odourant to separate from the test-fluid mixture, it was determined that incorporation of the odourant into a binary azeotrope involving one of the other essential test-fluid components was possible. The odourant-containing azeotrope was found to possess an acceptable vapour pressure, a high odourant mole-fraction in the vapour phase, and sufficient miscibility in the remaining test-fluid components.

Choice Of Detector

Choosing the definitive detector for the new leak-location method proved to be a difficult exercise and involved the evaluation of several different technologies. Catalytic combustion detectors ("sniffers"), although effective for detecting some compounds, were ineffective for the selected odourant, and in any event could not operate continuously along an extended pipeline right-of-way. Infared spectrophotometers proved equally impractical due to the ease with which they are affected negatively by flammable vapours or water contamination. Several different gas chromatographs were evaluated, and although some showed detection thresholds of 0.1 ppm for the odourant, none were sufficiently portable to enable their use in the field (despite manufacturer's claims to the contrary). However, subsequent review of a widely-distributed body of literature ultimately suggested that domestic dogs were capable of meeting the detection sensitivity needs of the program, and were clearly able to fulfill the "portability" criterion as well.

An overview of this literature revealed that domestic dogs have been trained to detect exceedingly low concentrations of a wide variety of chemicals, many of which are associated with problems of substantialeconomic significance. For example, dogs have been used by the United States Department Of Agriculture to detect the egg cases of insects

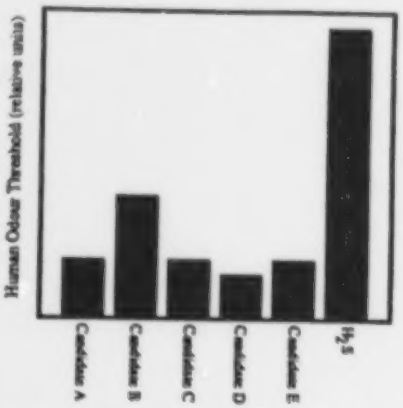

FIGURE 1. COMPARATIVE DETECTABILITIES OF ODOURANT CANDIDATES

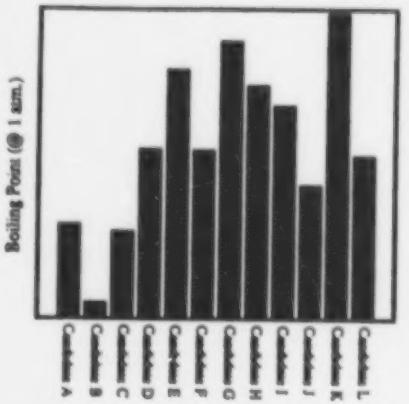

FIGURE 2. COMPARATIVE VOLATILITIES OF ODOURANT CANDIDATES

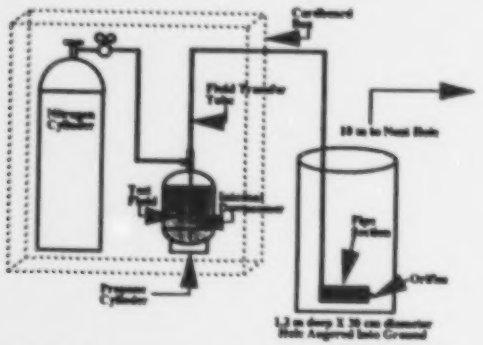

FIGURE 3. EXPERIMENTAL APPARATUS FOR LEAK DETECTION TESTS

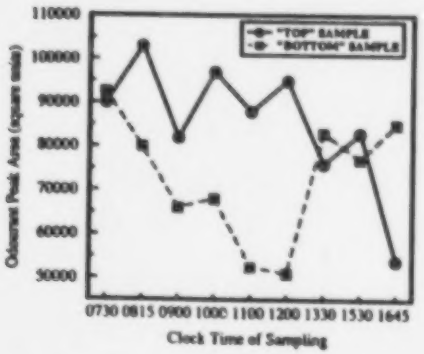

FIGURE 4. TEST FLUID COMPONENTS PARTITIONING ANALYSIS

TABLE 1.

AQUEOUS SOLUBILITIES OF ODOURANT CANDIDATES

ODOURANT CANDIDATE	AQUEOUS SOLUBILITY
A	insoluble
B	slightly soluble
C	slightly soluble
D	slightly soluble
E	slightly soluble
F	insoluble
G	insoluble
H	slightly soluble
I	insoluble
J	slightly soluble
K	insoluble
L	insoluble

TABLE 2.

ODOURANT CONCENTRATIONS IN AIR SAMPLES TAKEN AT "GROUND LEVEL" FROM THE EXPERIMENTAL APPARATUS

TIME (hours)	ODOURANT CONC. (ppm)
1	0.2
2	32.4
3	15.1

responsible for defoliating vast tracts of American forest (5,6). Dogs have also been trained to locate locust infestations in American homes (7), identify seventeen different chemical accelerants used by arsonists (8), find explosives (9), detect the presence of drugs and firearms (8,9,10), locate breaks in underground power cables (11), and to detect certain products leaking from buried pipelines (3). Researchers from the Department of Forensic Medicine at the University of Leeds are using trained dogs to check / calibrate a prototype machine which is being developed to identify criminals by matching the scent on articles found at crime scenes with that from suspected felons (12). Similar work is being conducted by police agencies in the Neatherlands (13). The U.S. Environmental Protection Agency and the New Jersey Institute of Technology use dogs to "sniff out" toxic chemical leaks which could not as quickly or effectively be detected using conventional instruments (14). However, although dogs have been used successfully to detect low concentrations of various chemicals, past technological restraints have limited our ability to quantify the limits of a dog's olfactory system. Despite this lack of precision, some researchers have "estimated" that dogs are capable of detecting certain chemicals at levels of 1 part per trillion (15,16,17). However, controlled laboratory tests have shown that the absolute olfactory threshold of dogs is substantially less than 1 ppt. Two independent research efforts using operant conditioning (18), and electroencephalographic and behavioral olfactometry (19), have measured the minimum sensitivity of dogs to specific compounds at 10-15 to 10-18 molar.

Once a suitable odourant had been chosen and dogs were identified as the best available detector, a number of experiments were conducted to test the feasibility of the overall leak-detection technique. The following section summarizes that work.

EXPERIMENTAL PROCEDURES AND RESULTS

Laboratory Leak-Detection Experiment

Experimental Design. Prior to field testing the new leak-detection method, a laboratory experiment was conducted to evaluate the ability of the odourized azeotrope to dissociate from other test-fluid components and percolate to the soil surface.

A schematic representation of the apparatus used for this test is shown in Figure 3. The test-fluid was transferred to an empty propane tank which was then inverted and pressurized to 345 kPa with nitrogen. As nitrogen was released from the system, test-fluid was forced through a 6 mm PVC and steel tube to a small section of pipe having a hole 0.4 mm in diameter drilled through one end. This assembly was placed at the bottom of a container formed by welding 2 oil drums together, and then filled with finely crushed rock (3-6 mm diameter). As test-fluid was allowed to flow through the apparatus, it was subsequently forced through the hole in the buried pipe and into the surrounding gravel. The test apparatus was designed to allow 16 litres of the fluid to flow into the barrel within a 2-hour period. Air samples were taken at one-hour intervals above the barrel using a small air pump and Tedlar bags. Samples were later analysed using gas chromatographic techniques.

Test Results. One hour after commencement of the experiment, a faint odour of could be detected (by the human nose) at the top of the container. Approximately one half hour later, a strong odour was evident, which persisted.

Table 2 shows odourant concentration, as measured by the gas chromatograph, in samples collected over a three hour period. A barely-detectable concentration (0.2 ppm) of the odourant rose to the "soil surface" within the first hour. Surface concentrations peaked during the second hour (32.4 ppm) and decreased by the third hour to approximately 15 ppm.

Test-Fluid Partitioning Test

One final consideration relevant to the test-fluid needed to be addressed before full-scale field trials could be conducted. For the test-fluid to be effective, the odourant must remain in-phase within the test-fluid throughout the testing procedure.

Experimental Design. To test the degree of partitioning of test-fluid components, a container of the fluid was prepared. Homogenization of the mixture was accomplished by vigorously agitating the container for a period of 5 minutes using a Red Devil paint mixer. Grab samples were taken from the top and the bottom of the container over a period of nine hours, and then analyzed for odourant concentration using gas chromatographic techniques.

Test Results. Results are summarized in Figure 4. Although a certain degree of odourant migration occurred within the test-fluid mixture, it was evident that the odourant did in fact remain in phase.

Training Of Leak-Detection Dogs

Before full-scale field trials could be conducted, dogs needed to be obtained, evaluated for their suitability to the task of leak-detection, and then trained to detect the odourant. Esso solicited the help of personnel from the Interdiction and Intelligence Branch of Canadian Customs to procure and train a single dog to test the feasibility of using animals as leak detectors. It soon became evident that dogs were capable of detecting the odourant, and of working through a concentration gradient of vapour ("cone of scent") to indicate areas where the odourant was found rising from the soil surface. Once the effectiveness of using dogs was established, a private firm, Command Dog College Ltd., was contracted to purchase, evaluate and train a number of animals for leak-detection work. Training was conducted over a period of approximately 10 weeks. Once this program was complete, the dogs were capable of "tracking" the odourant along open rights-of-way as well as in partially-backfilled trenches. They were also trained to exhibit strong digging behavior at those sites where they detected the highest concentration of odourant exiting the soil surface. In addition to being trained to track the odourant, dogs were physically conditioned to ensure they would have the stamina required to work for long periods in the rough terrain encountered along pipeline rights-of-way.

Full-Scale Field Trials

After the training of the leak-detection dogs was complete, two full-scale

field trials were designed to evaluate the capability of the overall leak-location technique.

Experimental Design. In total, nine leaking pipelines were fashioned from 15-20 cm long sections of 114 mm pipe, welded shut at both ends. The apparatus employed in these tests was similar to that utilized during the laboratory experiments described earlier (see Figure 3). To mimic leaking pipelines, ports measuring 0.8 mm in diameter were drilled into brass plugs which were then threaded into the end caps of each pipe. The flow rate of test-fluid from each orifice was calibrated in the laboratory to ensure all the test-fluid would leak from the apparatus within approximately 2.5 hours.

To minimize excavating extensive sections of pipeline trench, one site was constructed so as to "simulate" right-of-way conditions. This was accomplished by augering 20 holes to a standard pipeline burial depth of 1.2 m. Spaced at 10 m intervals, the holes functioned as a 200 m long right-of-way. Of the 20 holes augered, 5 were prepared as experimental (leak) sites, and 15 were prepared as controls. The position of experimental-versus-control sites was established using a random number generator and neither the authors nor the dog handler knew which sites contained the leaks. To avoid the dogs equating the presence of surface equipment with the presence of leaks, all experimental and control sites were made to appear similar.

The second site was prepared somewhat differently. Here, a 400 m long trench was excavated to a depth of approximately 1 m and holes were augered into the bottom of the trench. Prepared in this manner, the second site allowed dogs to become accustomed to working in partially-backfilled trenches, a condition not uncommon where new pipelines are being pressure tested. Four experimental leaks were prepared at this site: three were buried to a depth of 1.2 m; the fourth was buried at 3.7 m.

To prevent plugging of the leaks with soil, paper towelling was taped over the orifice in each section of pipe, and a small quantity of gravel was placed at the bottom of each hole. A length of 6 mm carbon-steel tubing was fitted to the sections of pipe prior to lowering them into the augered holes. Additional gravel was then placed so as to barely cover each pipe, and all holes were then backfilled with native material. The ends of the tubes extending from buried pipes at the experimental sites were connected to propane cylinders containing 16 L of test-fluid, and the tanks were placed 3 m from the holes.

All equipment used at experimental locations was cleaned and subsequently rinsed with water so as to remove any traces of odourant which may have contaminated these sites. To ensure consistent treatment of all test facilities, equipment at the control sites was purposely contaminated with test-fluid and then decontaminated using the same procedure as employed on experimental sites.

To begin the field tests, nitrogen was forced into the cylinders of test-fluid (see Figure 3) at a specific pressure calculated to achieve the desired flow rate of test-fluid. The leaking pipes were left to release test-fluid into the surrounding soil for a period of approximately 2.5

hours. Two hours after all the test-fluid had been expelled from the cylinders, a dog was introduced to the site and challenged to locate the leaks. Prior to, and directly after working the dog along the simulated pipeline rights-of-way, grab samples of air were collected in Tedlar bags above each experimental site. These samples were later analysed in the laboratory for odourant concentration.

Test Results. During the first field-trial, the dog correctly indicated the presence of the odourant at four of the five experimental sites. This result was initially seen to represent a success rate of 80 percent; however, subsequent mass-balance determinations performed on the cylinders of test-fluid confirmed that one of the experimental sites had in fact not leaked. The dog had therefore correctly "indicated" on all 5 sites. Results from the second field trial were similar, with dogs correctly indicating four out of four leak locations, including the leak buried 3.7 m subsurface. (The latter leak was not detected in the initial trial run; however, a subsequent series of runs spaced several hours apart, showed the dogs capable of detecting the leak after 48 hours.)

Of the nine leaks presented to the dogs, GC analysis was able to detect only two (airborne odourant concentrations were measured at 19 and 2.5 ppm).

DISCUSSION

The experimental data presented above clearly demonstrate that the new leak-detection procedure met all the technical challenges identified at the onset of the research program. The test-fluid mixture performed according to design, with no undesireable phase separation encountered during any of the tests. Similarly, the dogs trained to detect the odourant exceeded all expectations. These animals proved to be easily trainable to detect the odourant and were shown to be capable of accurately pin-pointing the location of subsurface leaks. As noted, dogs, on occasion, even "informed" research personnel of the failure of certain test apparatus, and easily out-performed gas chromatographs in detecting the odourant.

Since completion of the experimental portion of the leak-detection program, the technique has been utilized on six actual pipeline leaks. One of these incidents involved a 10 year old produced-water line which had been buried to a depth of 2.1 m in compacted clay soil. Another incident involved a glycol pipeline which had been in service for 28 years. The leak in the produced water line was detected under particularly challenging soil and weather conditions (in clay-rich soil, in frozen ground, after a lengthy period of minus 40 C temperatures).

CONCLUSIONS

Results collected from a series of studies conducted over a two-year period confirm the feasiblity of using an odourized test-fluid and trained domestic dogs to accurately locate pin-hole leaks in buried pipelines. Using the detection methods described, leaks as small as 0.8 mm were detectable to a depth of 3.7 m. During the leak-detection program, the new technique was tested on nine experimental leaks and six failed pipelines. All fifteen leaks were successfully located. Additional research is planned to better define odourant percolation rates under various soil conditions, to more precisely define the physiological detection threshold

of the dogs for the test-fluid, and to establish the overall limits of the technique.

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OIL FIELD BRINES: ANOTHER PROBLEM FOR LOUISIANA'S COASTAL WETLANDS

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Introduction

The rapid rate of loss of coastal wetlands in Louisiana has become a major issue with economic, political, and technical components. With 40% of the nation's coastal wetlands disappearing at a rate of approximately 40 square miles per year, the impact on commercial fisheries, trapping, recreational use and the people who live there is a major concern of residents, politicians and scientists (Fig. 1). Attempts to understand the causes of wetland loss have produced a long list of natural processes and human activities that have contributed to the problem. Coleman and Roberts (5) have provided a comprehensive summary of factors contributing to the loss of deltaic coastal wetlands.

It is generally accepted by the scientific community, although not generally appreciated by the public, that wetland loss is a natural part of the deltaic processes that have built south Louisiana. As delta lobes are abandoned by avulsion upstream, distal wetlands subside by compaction, are invaded by salt water from the Gulf of Mexico, and are eroded by wave action. There is also general agreement that human activities have contributed significantly to marsh loss. Flood-control levees along the lower Mississippi and control of the channel for navigation have robbed the downstream marshes of sediment. Canals dredged for navigation, for access to oil and gas drill sites, and for pipelines have interrupted the normal hydrology and fostered saltwater intrusion. There is also concern that some marsh management programs, intended to increase productivity, may actually contribute to wetland loss in some settings.

A substantial body of literature documents the stress that increased salinity places on marsh plants adapted to lower-salinity regimes. Although there has been discussion of the role of saltwater intrusion in marsh loss, relatively little attention has been paid to the role of the discharge of salt water into marsh areas as a result of human activities. Oil and gas operations are the chief human contributors of saline waters to the Louisiana coastal area. This paper describes these discharges, summarizes the effects of increased salinity on marsh vegetation, and discusses the implications for marsh deterioration.

Fig. 1. Louisiana coastal wetlands and brine discharge points.

Background

The fluid produced from oil wells normally consists of oil, gas liquids, and salt water. The salt water produced along with the crude petroleum is generally called "produced water" or "oil field brine" by the petroleum industry and regulatory agencies. Produced water is the highest-volume waste generated by oil and gas operations. It contains both dissolved and suspended solids, (including such dissolved salts as sodium chloride) dissolved hydrocarbons, and trace metals.

From 2 to 99% of the total fluid produced from an oil well is salt water; produced water constitutes an average of 85% of the fluids produced from Louisiana oil fields (20). Higher percentages of produced water are associated with older fields (6, 19).

The three alternatives for disposing of produced water are (1) injection into disposal wells (90% of U.S. produced waters are injected), (2) storage in tanks, pits, or other containers, and (3) discharge into surface water. The U.S. Environmental Protection Agency (EPA) reported a statewide ratio of produced water injected per volume of oil production in Louisiana of 5 bbls of water/1 bbl of oil (bbl=barrel=42 gallons) (20). Most produced water in north Louisiana is reinjected for enhanced recovery or disposal onsite or at a commercial facility.

Between 1901, when the first oil well was drilled near Jennings, and 1953, state regulations allowed the discharge of produced waters into most surface waters. In 1953 the Louisiana Stream Control Commission required that oily waste be removed from salt water before it could be discharged. The State Department of Conservation promulgated regulations in 1965 governing the injection of produced water to prevent the pollution of freshwater supplies. In 1968 the Louisiana Stream Control Commission altered its regulations governing oil field brine and prohibited discharges in freshwater bodies and their drainage areas. However, these regulations state that "salt water may be disposed of in normally saline waters, tidally affected waters, brackish waters or other waters unsuitable for human consumption or other purposes." This has resulted in the discharge of a large volume of produced water into fresh and brackish marsh areas. Additional exemptions to the restrictions against discharges in freshwater bodies are given for the Mississippi River and its distributaries south of Venice and the Atchafalaya River south of Morgan City.

Since 1968 there have been no changes to further restrict the discharges of produced water in Louisiana's coastal zone. In 1985 the Louisiana Department of Environmental Quality (DEQ) promulgated regulations that required permits for all oil field wastewater discharges. A DEQ survey of oil and gas operators in 1986 revealed that oil field brines were being discharged to surface waters at 698 different locations in Louisiana's coastal parishes, with a total volume of 2.64 million barrels per day.

Produced water can contaminate soils or surface waters and can destroy vegetation, aquatic organisms, and agricultural productivity. Produced water

may contain many toxic substances and, therefore, can be considered hazardous under the definition of the federal Resource Conservation and Recovery Act of 1978. Most instances of damage from produced waters in Louisiana relate to its high chloride content and its "virtually permanent" damage to soils and vegetation (20).

The primary sources of data used to identify and characterize produced water discharges and their effects were DEQ, the Louisiana Geological Survey, the U.S. Geological Survey, and EPA. Documentation of the impacts of the exposure of wetlands to pollutants commonly found in produced water was obtained from a review of published and unpublished literature.

Produced Water Disposal Practices

Oil production operations generally include the gathering of the produced fluids (oil, gas liquids, and water) from a well or group of wells, and separation and treatment of the fluids. As oil is depleted from the producing formation, pressure differentials cause water to flow in from adjacent formations. As a result, water-to-oil ratios increase with the production life of an oil well. Stripper wells (i.e., those that produce less than 10 barrels of oil per day) may produce more than 100 barrels of salt water for each barrel of oil.

State regulations prohibit the surface discharge of oil field brine in areas north of the coastal zone. Injection is the most common method of disposal where discharges to surface water are not allowed. Louisiana oil field operators and commercial disposal companies injected 794,030,000 barrels of produced water in 1985 (20). This figure was derived from injection well reports required by the Louisiana Department of Natural Resources.

In 1986 DEQ notified state oil and gas operators that existing discharges of oil field waste must be reported and ultimately receive a permit. Responses to this request for information through November 1987, identify the location and volume of 698 point source discharges of produced water. The total reported volume of produced water discharged into coastal surface waters in 1986 was 962,682,498 barrels (Table 1).

These reports indicate that 70% of the produced water from oil field operations in Louisiana is discharged into surface waters. Virtually all of these discharges are located in the coastal zone. The volume of produced water discharged in each coastal parish is presented in Table 2. In addition to produced water from over 300 onshore fields, coastal oil and gas facilities process oil and salt water produced from the federal Outer Continental Shelf (OCS) and state offshore waters (Fig. 2). A recent study conducted by the U.S. Minerals Management Service indicated that 23% of the produced water discharged into the Louisiana state coastal waters is transported onshore from the federal OCS (4). The volumes of these discharges are reflected in the industry reports summarized in Table 1.

Total discharge of produced water from 14 onshore fields in 1986 is presented

TABLE 1

Recent estimates of Louisiana produced water volumes and disposal practices from three independent sources

Total Annual Volume (barrels)	Disposal Methods	Data Source
794,030,000	Injection	Injection well Reports for 1985, Louisiana Department of Natural Resources
1,346,675,000	Undifferentiated, includes injection	Industry Survey, American Petroleum Institute, 1985 (24)
962,682,495	Discharged to coastal surface waters	Industry Survey, Louisiana Department of Environmental Quality, 1987

TABLE 2

Reported brine discharged to Louisiana coastal waters, by parish (21).

Parish	Barrels/Year
Terrebonne	314,272,847
Plaquemines	271,440,967
Jefferson	82,472,881
Lafourche	65,798,258
Iberia	61,228,750
St. Bernard	53,829,835
St. Mary	49,150,535
Cameron	27,002,335
Vermilion	22,780,088
Calcasieu	7,613,535
St. Charles	6,828,237
Orleans	147,825
St. Martin	100,375
St. Landry	8,030
TOTAL	962,682,498

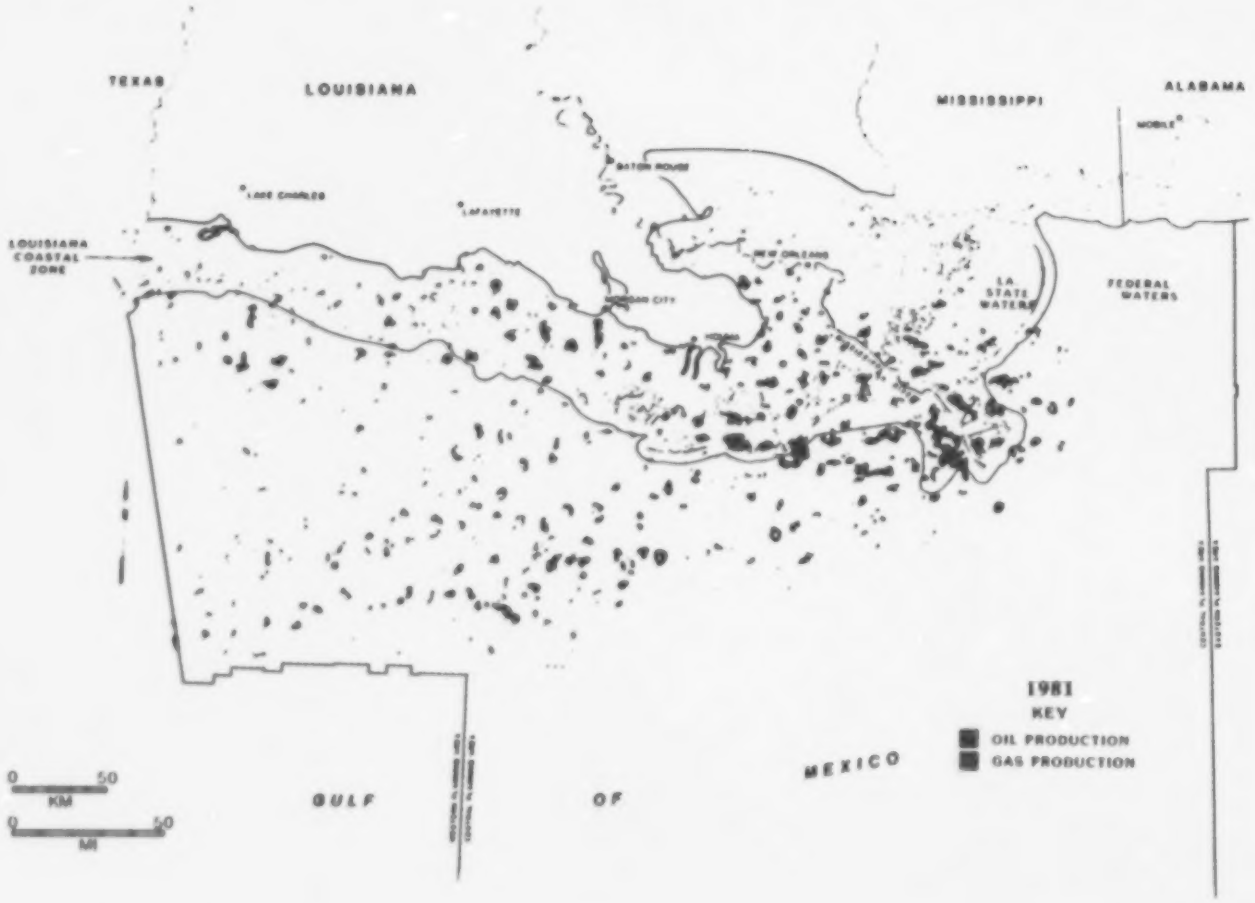

Fig. 2. Louisiana coastal and offshore oil and gas fields.

in Table 3. These are representative major fields located in the coastal zone; all but one was discovered before 1970. The total volume of brine discharged from these 14 fields in 1986 was 150,660,190 barrels.

Chemical Composition of Produced Waters

While most oil field brine is believed to be of marine origin, the composition and ionic ratios of these waters is quite different from that of seawater. The chemical properties of oil field brine are the result of physical and chemical changes before, during, and after sediment consolidation. The composition of the interstitial water deposited with marine sediments changes as the water reacts with rock. The most dramatic chemical change results from the dissolution of halite (6).

The salinity of oil field brine is generally much higher than that of the water originally deposited with marine sediments and commonly ranges from 50 to more than 150 ppt. The dissolution of salt diapirs, which have migrated upward through Gulf Coast sediments, is the primary and ongoing source of high salinity levels in Louisiana oil field brine (11, 17, 30).

Oil field brine is often close to saturation with sodium chloride. The removal of all chlorides would virtually desalt the brine. An examination of U.S. Geological Survey records for 178 brines sampled in Calcasieu and St. Charles parishes revealed that chloride concentrations varied widely, but on the average exceeded the chloride concentration of seawater (18,980 ppm) by a factor of 3 to 4 (Table 4).

Ions in greatest concentrations in produced waters other than chloride (Cl) and sodium (Na^{+}) are calcium (Ca^{+2}), magnesium (Mg^{+2}), and potassium (K^{+}), listed in decreasing order of abundance (6).

In addition to chemical constituents naturally occurring in subsurface brines, produced water often contains substances associated with oil field drilling and production practices at the well site. These include chemicals used for acidizing the producing formation (e.g., acetic, formic, and hydrochloric acid), corrosion inhibitors, surfactants, friction reducers (primarily organic polymers), ethylene diamine tetracetic acid (EDTA) to dissolve pipe corrosion, and cleanup additives to remove reactor products and reagents. Although the formation may retain some of these fluids, most are eventually pumped to the surface at the well head with brine or oil (20).

Sampling conducted by EPA in 1986 identified several chemical constituents in oil and gas extraction waste streams in "amounts greater than health based numbers multiplied by one thousand." Of these constituents, benzene, barium, lead, and phenantherene were found in exceeding amounts in produced water tank bottoms (20). The organic constituents from the EPA "List of Concerns" or "Priority Pollutant List" include the hydrocarbons, benzene, napthalene, toluene, phenanthrene, bromodichloromethane, 1,2 trichloroethane and pentachlorophenol. The inorganic constituents of concern identified by EPA include lead, arsenic,

TABLE 3
Produced water discharges reported for 14 fields in coastal Louisiana in 1986 (Source: DEQ and Louisiana Geological Survey).

Fields	Parish	Barrels/Year
Caillou Island	Terrebonne	6,533,135
Lake Washington	Plaquemines	13,848,100
Lafitte	Jefferson	13,301,330
West Bay	Plaquemines	11,816,875
Garden Islands	Plaquemines	5,884,530
Lake Barre	Terrebonne	648,970
Leeville	Lafourche	1,657,100
Weeks Island	Iberia	24,382,000
Point-a-la-Hache	Plaquemines	4,577,100
Eloi Bay	St. Bernard	6,296,250
Half Moon Bay	St. Bernard	31,641,120
Lapeyrouse	Terrebonne	19,942,870
Bayou Penchant	Terrebonne	1,460
Quarantine Bay	Plaquemines	10,128,750
TOTAL		150,660,190

TABLE 4
Chlorinity values for produced waters in two coastal parishes (Source: U.S. Geological Survey, Bay St. Louis, MS).

Parish	Number of Produced Waters Sampled	Chlorine Concentration in Produced Water (ppm) High	Low	Average	Ratio of Produced Water Chlorinity to that of Seawater
Calcasieu	127	195,776	3,800	62,645	3.3
St. Charles	51	136,110	360	74,570	4.0

barium and antimony. Table 5 presents results of analyses conducted by EPA of produced water discharges from four south Louisiana facilities.

Ecological Impacts of Increased Salinity

The most widespread and frequently reported problems associated with the discharge of oil field brine in Louisiana involve damage to local plant life and soils. When brine is discharged into freshwater areas and uplands severe salinity problems for organisms intolerant of increased salinity may result. Estuarine and marsh habitats can also be impacted by the unusual ionic components and ratios in produced water.

Even the most salt-tolerant plant species are unable to withstand natural marine salt concentrations above 50 ppt (18). The natural zonation of marsh grasses in fresh to saline environments indicates the limits of ability of these species to regulate salt content.

The effects of excess salt and high salinity on dominant wetland plants are well documented. High salinity affects plant growth 1) osmotically, 2) by direct toxicity, and 3) by creating a nutrient imbalance (15). Panicum hemitomen, a common grass in freshwater marshes, for example, will die within four days after exposure to 10 ppt salinity, which is roughly one-third the salinity of seawater (35 ppt.) (13).

Pezeshski et al. (12) found that bald cypress (Taxodium distichum) seedlings can tolerate and recover from short-term exposure to salinity levels less than 3 ppt. Above that level they cannot acclimate and ultimately die from reduced photosynthesis and metabolic stress. Even the slightest increase in salinity causes leaf injury and root damage to bald cypress seedlings (14).

In studies designed to simulate salt stress resulting from exposure to seawater and brine discharges associated with oil and gas operations, Pezeshski et al. (13) found that photosynthetic rates in P. hemitomen declined between 20% and 67% within one day of saltwater exposure. Gas exchange rates were reduced between 55% and 80% within one day.

Pezeshski et al. (14) found that photosynthetic rates and biomass production of Spartina patens were strongly and adversely affected by increases in salinity. Net photosynthesis was reduced by 43% as soil salinity increased from 0 to 22 ppt. S. patens is the domiant vegetation type in the brackish marshes of Louisiana's coastal zone. Studies show that brackish marshes are deteriorating faster than any other wetland type in Louisiana (10, 1, 20).

Spartina alterniflora is the most common saline marsh grass in Louisiana and also the dominant plant species of the backbarrier marshes of Louisiana's barrier islands. Backbarrier marshes play an important role in binding eroded sediment which would otherwise be lost during the landward migration of these islands (8). Parrondo et al. (15) found that S. alterniflora seedlings grew best at salinities of 5-10 ppt and that root and shoot growth was inversely related to substrate

TABLE 5

Analytical results of sampling conducted by U.S. Environmental Protection Agency at end points of four produced water discharges in south Louisiana. Asterisk denotes EPA "priority pollutant" (22).

Average	Sun Exploration and Production Co., Sweetbay and Bateman Lake Tank Battery St. Mary Parish, La.	Tidewater Canal Leeville Lafourche Parish, La.	Texaco, Inc. Leeville Lafourche Parish, La.	Texaco Tank Battery No. 3 Golden Meadow Lafourche Parish, La.	
203	17	300	460	35	Oil and grease mg/l
685	809	1,504	160	266	p-cresol ug/l
1,846	1,849	3,520	1,061	953	Toluene* ug/l
2,339	1,510	6,334	153	1,358	Phenol*
47	0	33	20	34	Bis(2-Ethylhexyl) phthalate*ug/l
2,126	3,207	2,880	1,180	1,223	Benzene*ug/l
8,923	1,090	9,390	2,010	23,200	Iron ug/l
4,165	2,080	8,940	0	5,640	Lithium ug/l
2,010,000	80,100	130,000	6,600,000	1,230,000	Magnesium ug/l
882	280	1,240	1,500	508	Manganese ug/l
30	0	0	0	120	Molybdenum ug/l
253,250	120,000	341,000	257,000	295,000	Potassium ug/l
17,555	29,800	22,300	7,320	10,800	Silicon ug/l
38,400,000	14,300,000	45,600,000	13,000,000	80,500,000	Sodium ug/l
48,275	25,000	140,000	18,000	10,100	Strontium ug/l
18	0	49	0	24	Antimony*ug/l
111	404	0		40	Arsenic*ug/l
47,980	12,000	84,600	2,120	93,200	Barium ug/l
28,825	37,000	40,700	11,600	14,000	Boron ug/l
217	90	440	243	93	Zinc*ug/l
1,439,750	468,000	1,400,000	401,000	3,490,000	Calcium ug/l
154	133	307	108	67	Napthalene*ug/l
165,275	12,100	279,000	370,000	0	Sulphur ug/l

salt concentrations over 8 ppt. Produced water, which generally averages more than 50 ppt in Louisiana can have a major impact on this important marsh grass.

Salt tolerances of 14 common species found in coastal Louisiana are presented in Table 6. Even the most salt-tolerant species are unable to withstand exposure to salinity in excess of 50 ppt.

Most of Louisiana's coastal wetlands are subsiding as a result of sediment dewatering and compaction. Marshes of coastal Louisiana remain intertidal or above sea level by vertical marsh accretionary processes. A large portion of the organic matter produced by marsh plants is fixed in these accretionary processes (9). Reduction in the primary productivity of marsh plants by increased salinity will affect carbon cycling, which is important to vertical marsh aggradation. Reduction in the vertical accumulation of organic matter results directly in wetland deterioration and habitat change. Disruption of organic accretionary processes is especially damaging to wetlands that do not receive mineral sediment (13, 9).

Fresh and intermediate (slightly fresh) marsh plants fix carbon at approximately twice the rate of major species of plants found in brackish and saline marsh (i.e., Spartina sp.) (7). Thus, fresh and intermediate marshes are less vulnerable to subsidence and submergence as long as they are not stressed by other factors, such as increased salinity. Studies of marsh loss in Louisiana's Barataria Basin by Sasser and others (19) showed that marsh loss rates were "highest where fresh water marshes have been subject to salt water intrusion."

Although there have been many studies documenting the effects of salt stress on wetland vegetation, few have documented the direct effects of increased salinity on the chemical and microbial properties of wetland soils.

High salinity may reduce water absorption by clay minerals, reduce biologically available soil water supply, eliminate or reduce important soil fauna and flora, and retard the oxidative activity of various soil microorganisms (18). The unusual ionic components and ratios characteristic of oil field brines can directly affect the oxidation and reduction processes of wetland soils. For example, increased levels of ferrous and manganous compounds affect the activity of facultative anaerobic bacteria in the process of soil nitrification (2).

Discharges of calcium and sodium-rich oil field brines can contribute to increased calcium and calcium salts in the soil profile. These salts are responsible for high pH, which alters the natural oxidation/reduction potential in the soil (2).

The direct impacts of brine pollution on wetland plants can be observed over periods ranging from a few days to several months. The impacts on wetland soils can continue beyond the time required to destroy the vegetation and culminate in the "virtually permanent" damage to soils attributed to brine discharges and spills by EPA (20) and the U.S. Fish and Wildlife Service (18).

TABLE 6
Salinity tolerances of some typical plant species found in coastal Louisiana, modified from U.S. Department of the Interior (1978).

Species	Common Name	Bay or marsh type where normally found	Salinity (ppm) Low	High	Average
Ruppia maritima	Widgeon grass	Brackish Hypersaline	0[2]	45,000	25,000
Spartina alterniflora	Cordgrass	Salt	5,500	40,000	16,100
Distichlis spicata	Saltgrass	Salt/Brackish	5,000	50,000	14,200
Juncus roemerianus	Black rush	Salt/Brackish	1,000	45,000	
Scirpus robustus	Salt marsh bullrush	Brackish	6,000	39,000	
Spartina patens	Salt meadow cordgrass	Intermediate/Brackish	0	39,000	9,600
Scirpus olneyi	Olney bullrush	Intermediate/Brackish	5,000	17,000	9,200
Alternanthera philoxeroides	Alligator weed	Intermediate	0	15,000	1,400
Phragmites communis	Common reed	Intermediate/Fresh	0	20,500	
Vigna repens	Wild cowpea	Intermediate/Fresh	2,000	12,000	
Sagittaria falcata	Sythefruite arrowhead	Intermediate/Fresh	0	9,500	2,300
Cladium jamaicensis	Jamaica saw-grass	Fresh	0	3,000	
Panicum hemitomon	Maidencane	Fresh	0	1,000	900
Eichornia crassipes	Water hyacinth	Fresh	0	500	

Role of Produced Water Discharges In Wetland Loss

It is clear from the literature that the dominant wetland plant species in Louisiana coastal marshes are adversely impacted by significant increases in salinity. The impacts include reduction in plant vitality, decrease in vertical accretion of organic detritus, and deterioration of soil properties and processes. Intrusion of saline Gulf waters can produce these undesirable effects, resulting in the death of marsh plants, marsh break up, and increased rates of marsh erosion by waves and currents. Likewise, increased salinity from the discharge of produced water with total dissolved solids 3-4 times greater than sea water can have comparable or worse effects.

Examination of the locations of produced water discharge points in Louisiana coastal marsh areas shows a correlation between large numbers of discharge points in the Barataria Basin and adjacent areas with rapidly deteriorating marsh. Receiving waters (canals, streams, and water bodies) may dilute many of these discharges and others may, because of their density, sink to the bottom of receiving waters under "normal" conditions. However, storm waves and currents, periods of low rainfall and runoff, and tides can distribute produced waters into vegetated areas. Depending on the frequency of these processes, plants can be killed or suffer long-term chronic effects. Combined with subsidence, these effects can accelerate natural marsh loss rates and initiate vegetation loss in more stable, healthy marshes.

Figure 3 depicts the loss of wetlands in the Lafitte Oil Field in Jefferson Parish. The field currently produces about six barrels of brine per barrel of oil. Industry reports indicate that in 1986 up to 13.3 million barrels of brine were discharged into surface waters in the area shown. The average chloride concentration of the produced water in this field is 73 ppt. The average chloride concentration of the receiving water is less than 5 ppt. Roughly 30% of the wetlands within a 6-mile radius around the field disappeared between 1956 and 1978.

There have not been sufficient field studies to quantify the role of produced water in marsh loss. The coincidence of high rates of marsh loss with concentrations of brine discharge points in general and around oil fields with high volume discharges of produced water in particular is, at a minimum, strong circumstantial evidence that produced waters are a significant contributor to marsh loss in coastal Louisiana.

Fig. 3. Marsh loss in Lafitte field. Shaded area shows marshland area converted to open water between 1956 and 1978.

ACKNOWLEGEMENTS

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OIL FIELD DISPOSAL PRACTICES IN WESTERN KERN COUNTY, CALIFORNIA

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Abstract

Produced water disposal in western Kern County, California, has been by injection and infiltration from spreading ponds into the unsaturated zone, which is typically hundreds of feet thick. Regional geologic and engineering studies performed in western Kern County, California have evaluated the movement of waste water in the hydrogeologic environment. The west side of Kern County was then ranked, based on relative safety of ponding and/or injection of waste water.

Criteria for ranking is defined by hydrogeologic setting and the physical laws governing fluid flow in vadose and saturated subsurface formations.

The hydrogeologic setting in western Kern County is comprised of Pleistocene to Recent sediments. These formations have traditionally been described as unconsolidated sediments of continental origin which are difficult to map as separate units in the subsurface. However, within areas of adequate subsurface control, as in the west side oil fields, lithofacies have been

identified which are based on texture, mineralogy and electric log expression.

Fluid flow in the unsaturated zone is governed by two basic physical laws; that the movement of water is predominantly in the vertical direction and that clays that have been elevated above the saturated zone for long periods, as in a semi-arid or arid environment, do not behave as an effective barrier. Fluid flow in the saturated zone is stratigraphically controlled.

Oil operators in western Kern County have used these studies as a general framework for discussions with the agencies on area-wide management practices and for future disposal planning.

Introduction

Western Kern County is the location of many large oil fields (fig. 1). The California Water Quality Control Board Plan for the Lower West Side Kern County (1), contains strict guidelines regarding locations which may be permitted for oil field sumps and the qualities of waste water which may be contained therein and/or discharged therefrom. An amendment to the Basin Plan (October 22, 1982) relaxed the restrictions somewhat on the stipulation that it has been demonstrated that the "discharge will not substantially affect water quality nor cause a violation of water quality objectives".

Many geologists (2) have interpreted that subsurface inflow from the west side of the Valley provides up to 200,000 acre-feet per year of recharge and degradation of groundwater conditions. This interpretation has its basis in the inappropriate incorporation of water level and water quality data in a computer model which assumes a continuous aquifer.

Because of the possibility of groundwater degradation, a better understanding of the disposition of waste water was needed. The Pleistocene to Recent sediments contain useable groundwater and in other areas they are used as water disposal zones. One must understand how these sediments were deposited in order to provide the necessary geotechnical framework for the proper management of the groundwater resources in the San Joaquin Valley.

Historical Background of Waste Water Disposal

According to the California State Department, Division of Oil and Gas records, the Midway Sunset Oil Field was discovered in "about 1890". The requirements to add parentheses to the discovery date says a lot about the adequacy of historical records regarding this important natural resource.

The first recorded water production in the Midway Sunset field was in 1901 and in 1915 in the Buena Vista Field. In 1910, the famous Lakeview Gusher made so much oil that a dam was built in Section 34, T.32S., R.24E., not only to attempt to save as much of the oil as possible, but also to prevent its flowing into, and damaging the Buena Vista Lake Basin. This catch basin was to be the first of many such sites which were later used to trap oil, and aid in the percolation of waste water which had been discharged into natural drains in the area.

The bulk of the early oil production was of a low API gravity which was commonly accompanied by a substantial "cut" of formation sand. The universal method of dealing with this problem and cleaning up the oil in preparation for shipment to sales, was to produce the mixture into an earthen pit or sump. There, the sand settled to the bottom and the oil was skimmed off the top. This method also had the fortuitous advantage of allowing the water to percolate out the bottom. Thus, every operator and every property had its own water disposal system, which served until it finally filled up with sand, and/or plugged up with silt. This was rectified by cleaning out the sump, or by abandoning it in place and digging a new one. When viewed from the air, it is readily apparent that the entire field, particularly the Maricopa area, is honeycombed with old sumps which are no longer in use. When water quantities exceeded the percolation capacity of the sump, the excess was siphoned off and discharged into the nearest natural drain. This method was prevalent until well into the 1930's when better sand control methods started being utilized and the tank and boiler method of treating gained general acceptance.

In addition to Lakeview, numerous other catch basins were constructed, usually on a cooperative basis by several operators. The major ones were the Midway Basin, which stretched for a length of about two miles near the terminus of Buena Vista Creek just east of Valley Acres, and the Sunset Basin, which was on Sandy Creek, just off the extreme southeast end of the Buena Vista Hills. Around 1931, after a particularly bad storm which washed out the dams at many of the basins, the operators decided that they no longer wanted to maintain the basins on an informal basis. A cooperative was formed which became the Valley Waste Disposal Company. Some time during the 1930's, Valley Waste constructed several additional, major percolation and evaporation facilities.

By the early 1950's increasing water quantities were not only taxing existing facilities to the limit, but also their locations were such as not to afford adequate protection against eventual migration of percolated waters into the Buena Vista Lake Basin. In 1953 a study of the systems determined the origins and destinations of the various sources of produced water in the area. The Rickett and

Reaves report (3) proved invaluable in helping to fill the great void of factual data and information up the middle of the century. This report also served as the basis for locating sites for the facilities which now comprise the bulk of the Valley Waste system in the Midway Valley.

In the Midway Sunset and Buena Vista Oil Fields, the cumulative gross water production associated with the withdrawal of oil through 1986 was 3,178,000,000 barrels (4). The disposal of that water is by injection, treatment and re-injection, percolation, and evaporation. Percolation from surface impoundments is responsible for 2,328,000,000 or 73% of the historical total (4).

Geology

The Pleistocene to Recent sediments in San Joaquin Valley of California comprise the non-marine fill of the basin. Page (5) summarized and described the lithologies of the Pleistocene to Recent sediments. Page also recognized the same depositional environments identified by Lennon (6), but did not discuss the criteria for recognition of lithofacies in the subsurface. Lettis (8) also described the different depositional environments in a regional framework in northern San Joaquin Valley, subdividing lithofacies by composition and texture.

In different regions of the basin the sediments have been given different formation names. In western Kern County, the units are referred to as Tulare Formation and Alluvium. Detailed studies done for Valley Waste Disposal Company (4) documented the stratigraphic relationships of the Pleistocene to Recent units south of Elk Hills. One cross section from that effort is presented in fig. 2.

The Alluvium mapped by Dibblee (9, 10, 11) widely conforms with work done all along the west side (12, 13). In the subsurface this unit can be traced easterly towards Buena Vista Lake. It includes the fresh water aquifer and an interval identified as Tulare by Frink and Kues (14), in their "type description" of the Corcoran Clay, subsequently widely adopted in groundwater studies of the San Joaquin Valley. However, Frink and Kues did not correlate back to the surface, thus setting the stage for decades of water resources work which does not recognize the mappable delineation in the surface and subsurface between the aquifer containing the fresh groundwater sources in the San Joaquin Valley and other Pleistocene rocks.

The Tulare and Alluvium can be subdivided into lithofacies based on well log responses and petrographic data. Figure 3 illustrates the typical well log in the Midway Sunset and Buena Vista Oil

Fields, where: (1) the Alluvium is predominantly silty to clayey alluvial fan/alluvial plain; (2) the Upper Tulare is dominantly sandy alluvial fan/alluvial plain with some deltaic lithofacies; and (3) the Lower Tulare is lacustrine to deltaic. In other areas, the Alluvium, Upper Tulare and Lower Tulare do not necessarily have these same lithofacies. The typical well log characteristics of the various lithofacies are dependent upon what is filling the pore space (air, fresh water, salt water, or oil). By utilizing the density/neutron log in combination with the resistivities and core information the lithology can be determined. When air is in the pore space (due to the "gas effect") the apparent neutron porosity is much lower than the apparent density porosity, resulting in a "cross-over" of these two porosity curves. However, when the sands are fluid-saturated, the density and neutron porosities tend to have similar apparent porosities. Fresh water and oil/tar sands are highly resistive, whereas saline water sands have low resistivities. Because of this, the resistivity contrast between moisture-deficient sands and saline water sands, coupled with neutron/density log gas effects allows for an accurate determination of the water table elevation. Examples of this determination are shown in the Lower Tulare portion of fig. 3, and on cross section A-A' (fig. 2).

There are a number of obvious factors to keep in mind when discussing paleogeography of the Pleistocene to Recent.

1. Structures influenced depositional patterns.
2. The systematic unroofing of pre-Pleistocene rocks of the rising Temblor Range resulted in areal differences in texture.
3. The sedimentation rate has generally exceeded the subsidence rate resulting in almost complete progradation of Recent alluvial deposits over the Pleistocene lake.

The proximity of the rising Temblor Ranges to the axial trough of the valley restricted the alluvial fan/plain deposits of the Lower Tulare to a narrow band on the west side. During the emergence of the Temblors in the Pleistocene, there were several cycles of lacustrine transgression and regression. The approximate extent of four of these lacustrine transgression in the southwestern San Joaquin Valley is shown in fig. 4.

The alluvial fan/alluvial plain deposits are characterized by poorly sorted sheet flow deposits which have been eroded and reworked by streams. The Alluvial fan/alluvial plain deposits encroached upon the lake as shown on the block diagram of Midway Valley in fig. 5 during Mid-Tulare and the Present. The deltaic sands are shoreline deposits fed by fluvial systems which interfinger with lacustrine silt and clay basinward.

The present day basin is characterized by extensive alluvial fan/alluvial plain deposits which have completely encroached upon the lacustrine deposits. The texture of the Recent sediments directly corresponds to the texture of the adjacent outcropping formation as shown by the generalized texture map of the surface Alluvium (fig. 6). For example, the distribution of clayey alluvial fan deposits in the alluvium are adjacent to the Monterey shale outcrop and sand alluvial fan deposits are adjacent to the Point of Rocks sandstone.

Ranking of West Side Kern County for Relative Ponding Safety

The Ponding Categories which can be used to rank west side Kern County are defined by hydrogeologic setting and the physical laws governing fluid flow in vadose and saturated subsurface formation, schematically summarized in fig. 7 and are described as follows:

Category I ponding areas are characterized by the existence of Tulare outcrop exposure and/or topographic and sedimentary depressions which channel ponded water deep into the unsaturated Tulare Formation.

Category II ponding areas are the most dependent on physical fluid flow in the vadose and saturated zones. They are characterized by moisture-deficient alluvium over unsaturated Tulare where monitoring may prove valuable for future continuation of current practices.

Category III ponding areas are characterized by the existence of fluid saturated Tulare overlain by moisture-deficient alluvium. In these areas water may eventually find a pathway to the western central valley within the assumptions made in this report.

Applications

The ability to subdivide and the recognition of the lithofacies in the Tulare and the Alluvium has important applications in petroleum exploration and reservoir evaluation; waste disposal and regulatory compliance; and water resources management practices.

1. As described by Lennon (5), commercial steam soak projects in the Tulare are restricted to the deltaic lithofacies. Steam soak projects in the other lithofacies have not been successful.
2. The Alluvium and Tulare is commonly used for waste water disposal, therefore the relationship between waste water disposal units and units containing drinking water must be understood.

3. Also, from the standpoint of managing the groundwater resources, the proper geologic framework in which to evaluate water use is necessary to properly identify sources of recharge, overdraft and pollution.

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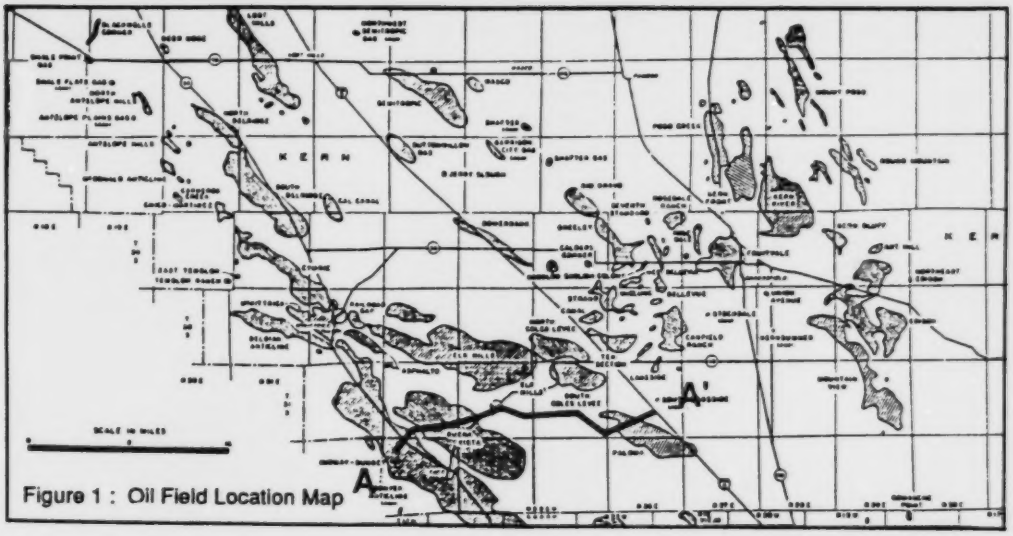


Figure 1 : Oil Field Location Map

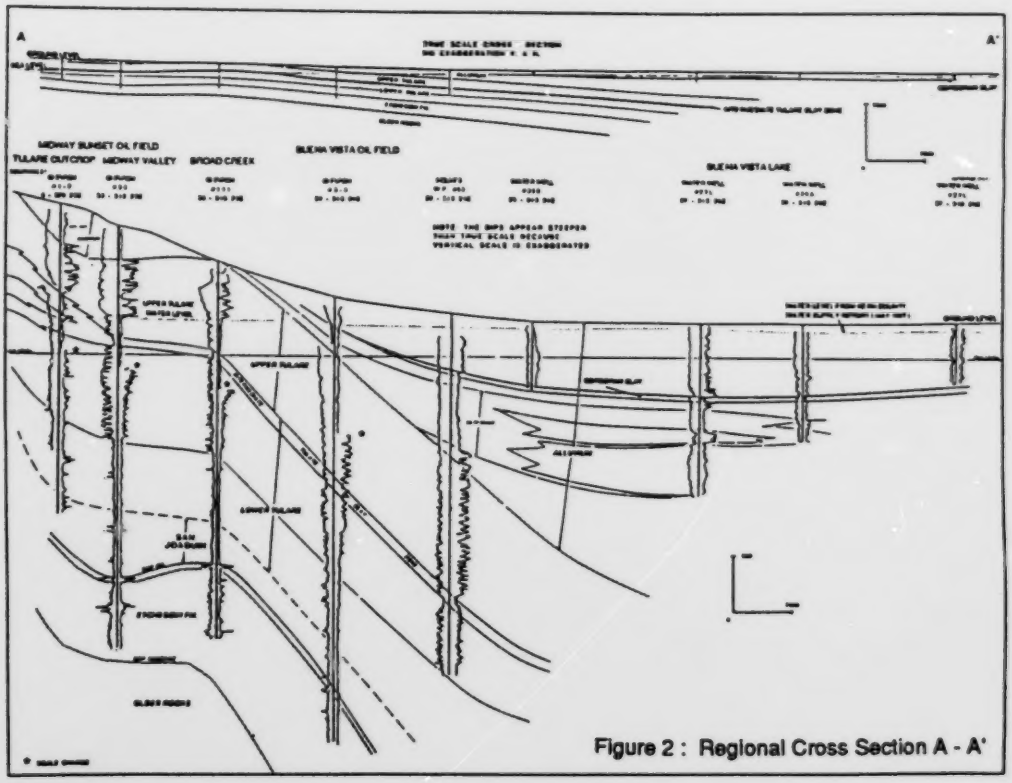
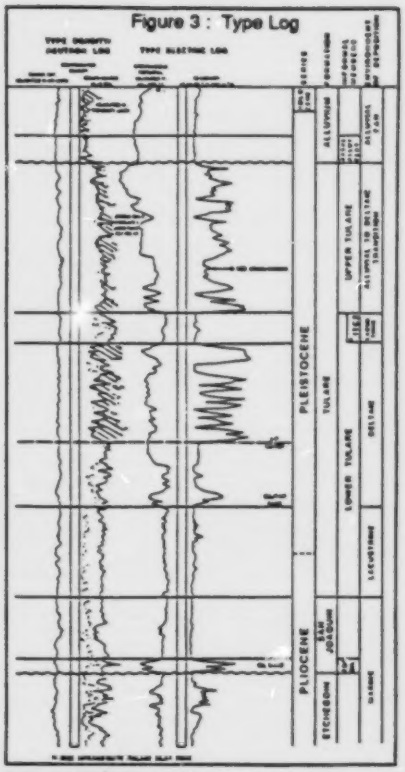


Figure 2 : Regional Cross Section A - A'



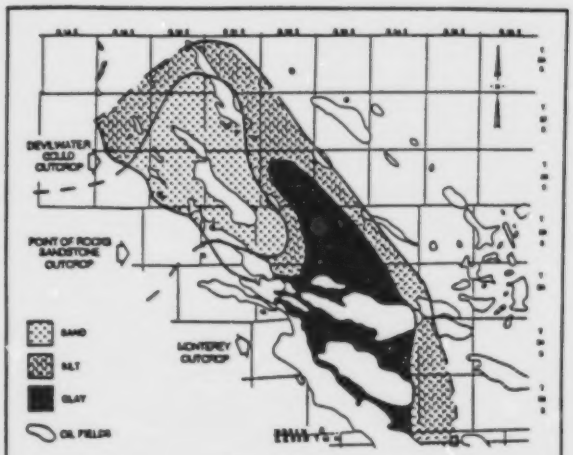


Figure 6 : Generalized texture map of the surface alluvium.

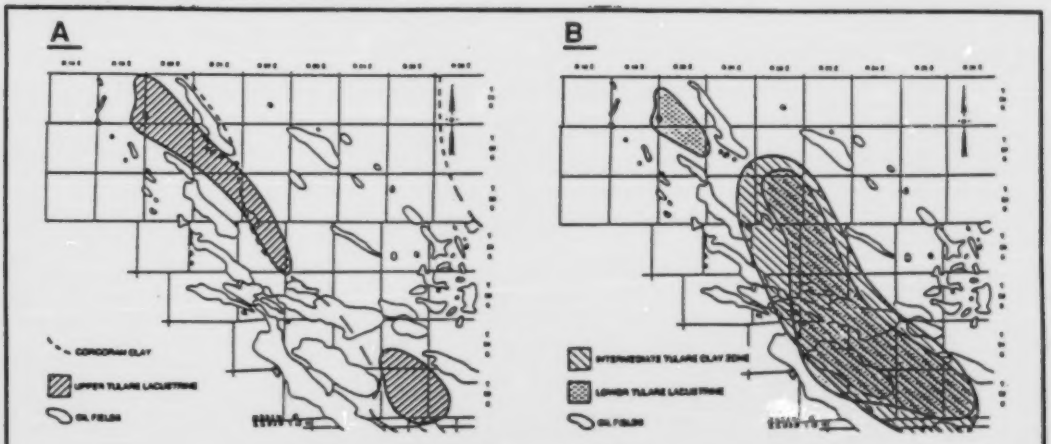


Figure 4 & 5 : Lacustrine distribution:
A) Corcoran Clay and Upper Tulare
B) Intermediate Tulare Clay Zone and Lower Tulare

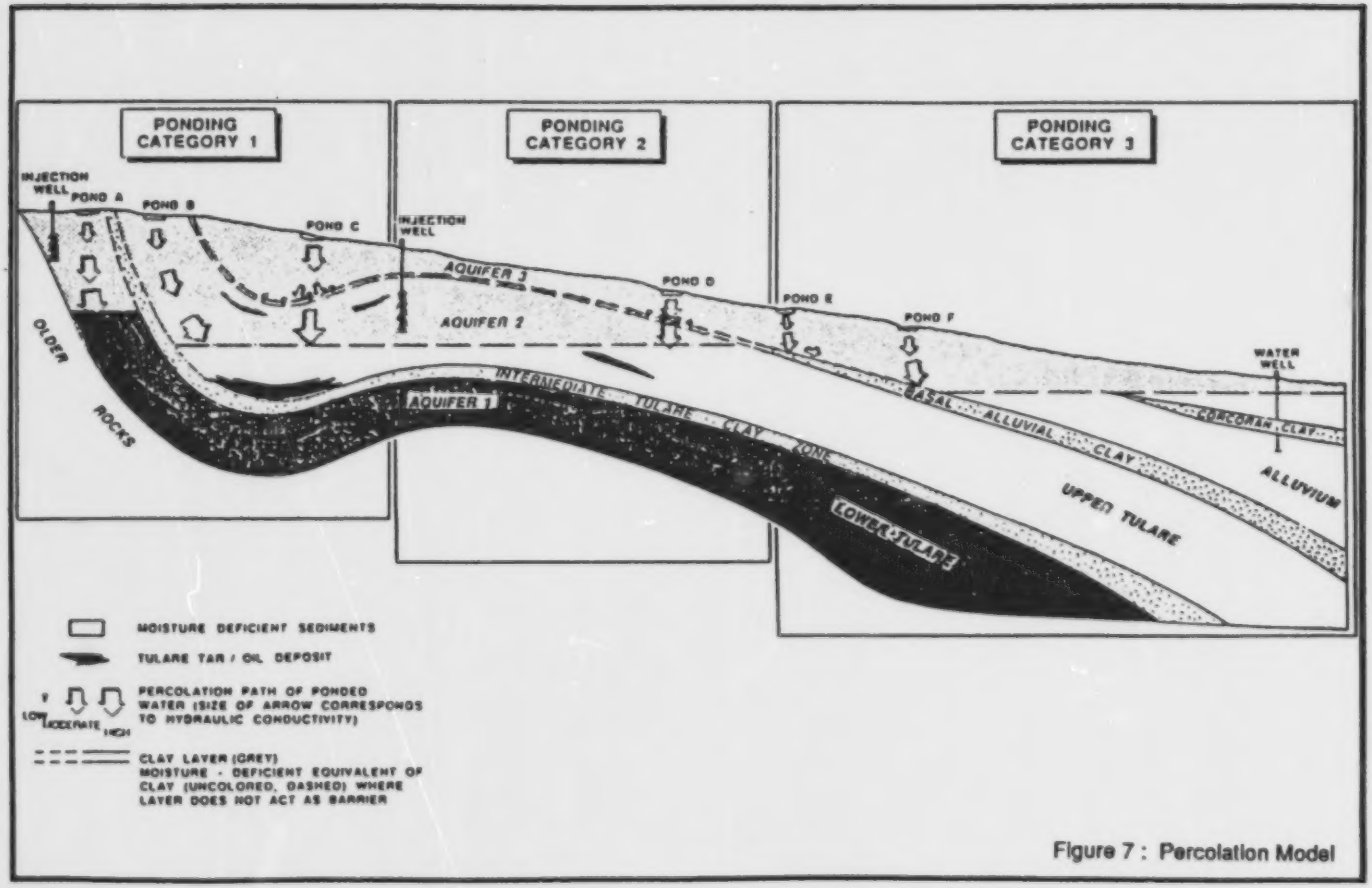


Figure 7 : Percolation Model

OIL WASTE ROAD APPLICATION PRACTICES AT THE ESSO RESOURCES CANADA LTD., COLD LAKE PRODUCTION PROJECT

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Abstact

Esso Resources Canada Ltd. operates the Cold Lake Production Project, which produces approximately 14,000 m^3 per day of bitumen (heavy oil) through cyclic steam stimulation technology. The Cold Lake Production Project is located 300 kms. north-east of Edmonton in Alberta, Canada. During the process of bitumen production about 6000 m^3 of oil sand waste per year is also produced. The majority of this waste material can be characterized as a liquid sludge consisting of bitumen, fine sand and water. The waste by-product is collected from plant vessels, tank bottoms, and through surface lease cleanup activities. The oil waste by-products are then stored in self contained pits on site. When inventory builds in the pits material is selectively removed and prepared for road surfacing.

The Alberta Energy Resources Conservation Board (ERCB) states in information letter IL 85-16 that road application as a disposal technique for oily wastes is not a long term solution. As a result of this position the ERCB has initiated a process to formulate acceptable practices for the disposal of oil wastes on roads through a joint industry/government task force on oil waste disposal. The task force has identified road application of oil wastes as a high priority topic in need of further discussion.

The Cold Lake Production Project has developed procedures to prepare oil waste for road surfacing and then apply it to major access roads within the project area to make a solid all weather road surface. The purpose of this paper is to describe the characteristics of the oil waste material, the methods for preparing the material for road surfacing and the application of the material to form the road surface. Further, data on the chemical and physical properties of the material are reviewed from an environmental perspective and comments are given on the need for environmental management procedures in the application of road surfacing materials. Conclusions are offered on the advantages of this procedure for road building.

Introduction

Oil wastes are an unavoidable by-product of oil sand development and production operations. In the early stages of heavy oil and oil sands operations in Alberta methods for collection, storage and disposal of oily waste material were ad-hoc and not applied consistently throughout the industry. This led to problems from an environmental perspective in that wastes became difficult to manage in terms of their distribution and potential toxicity. Additionally, a potential health hazard to workers exists with indiscriminate oil waste storage procedures. Further, disposal methods such as improper road oiling were potentially unsafe for motor vehicle operators.

The Alberta Energy Resources Conservation Board (ERCB) recognized the potential difficulties with oily wastes and published an information letter (IL 85-16) to all oil sand operators giving guidelines to the storage, handling, and disposal of oily wastes (1). These guidelines gave the first credibility to the option of disposing of oily wastes through application of the oily waste material on a municipal road. The information letter was clear in stipulating what types of roads were suitable for surfacing with oil waste in that no private roads could be surfaced and only under special situations would lease roads be allowed to be surfaced. The guidelines also specified the chemical parameters of concern to the ERCB and that the operator must quantify these parameters prior to using the road disposal option. A format for application to the ERCB for a oil waste management program was also provided at this time. Since 1985 however, still more questions have risen over the road oil disposal method. In May, 1988 the ERCB issued a letter (2) from the chairman to all oil sands operators stating that road oil application would in the future be limited to situations in

which the "operator can satisfy the ERCB that no alternate clean up or disposal technique are available".

The most appropriate application techniques for what has come to be termed road oiling remain elusive and inappropriate methods are still problematic from an environmental impact stand point. The most recent initiative (1989) in the road oiling area is a task force of government, (ERCB, Alberta Environment) petroleum industry, and researchers (Alberta Research Council) to investigate the most appropriate and environmentally sound road oiling procedures. The initial findings of this task force indicate that there are three major considerations that require clarification in the development of appropriate road oiling technology. These include; proper characterization of the oily waste material prior to use, appropriate road surfacing procedures, and environmental protection plans for surface roads.

Esso Resources Canada Ltd. (Esso) has been involved with road oiling at its Cold Lake Oil Sands Production Project for more than a decade and has during that time developed techniques for applying oil waste to roads that are pertinent to each of these road oiling information needs. The purpose of this paper is to describe the work done on road oil application at Esso with particular attention to waste characterization, application of oil to road surfaces, and the environmental implications of road oiling.

The Cold Lake Production Project

The Cold Lake Production Project (CLPP) is located in north - east Alberta, Canada near the Saskatchewan border, approximately 300 kms north-east of Edmonton, the capital city of Alberta. Experimentation and pilot operations have been occurred at Cold Lake since the mid 1960's, however it was not until the late 1970's that the Cold Lake Project was envisaged as an oil sands mega-project. An application was made to the ERCB for the mega-project in 1979 and it was subsequently approved in 1980. However, changes to the Canadian and world energy markets in the first part of the 1980's forced a new development strategy for the project. That is, certain aspects of the mega-project were discarded and the project was initiated on a phased development planning basis. In 1983 the CLPP construction was initiated and to date six "phases" have been completed and are operating. Each "phase" is to tap into specific portions of the oil-bearing sands within the original ERCB approved mega-project development area. Currently the CLPP is producing 14,000 m^3 per day of

bitumen production that reports to markets mainly in the north-eastern United States.

Oil Waste Characterization

During the process of bitumen production about 16m^3 per day or 6,000 m^3 per year of oil waste is generated. The oily wastes at CLPP come from two sources, as a by-product of bitumen production from the reservoir, and from surface lease clean-up activities. The majority of the oil waste is recovered from storage tanks and plant process vessels and has the general characteristics of a liquid sludge consisting of bitumen, fine sand and water.

Oil waste by-products are stored on site in self contained cement lined pits. When inventory of none recyclable oil wastes builds during the summer months, the material is selectively removed from the pits for road surfacing. The oil waste material is first characterized for its chemical constituents. The samples for chemistry analysis are taken at each oil waste pit. The sampling is unique in that the waste pits themselves comprised of two sub-pits, one for liquid phase waste and one for solid phase. The solids pit is above grade in comparison to the liquid pit and heat is applied to both pits to encourage liquids movement to the lower pit. Liquids are then recycled through the plant facilities. Grab samples are taken on a grid across both pits and averaged to obtain a representative value.

The typical chemistry of Cold Lake oily waste is given in Table 1. The nature of the material can be summarized as a viscose hydrocarbon material mixed with varying, but small, amounts of organic and mineral debris. The environmental implications of the content of metals and organic chemicals is discussed later in this paper.

Table 1. Chemical characterization of Cold Lake oil wastes used in road application.

Parameter	Value (yearly average)
Physical Properties	
Oil (%)	13.0
Liquid (%)	7.5
Solid (%)	79.5
Inorganic Chemicals (PPM)	
Chlorides	780
pH	6.9
Metals	
Boron	0.01
Cadmium	0.001
Chromium	0.066
Mercury	0.0001
Manganese	0.03
Lead	0.05
Vanadium	0.05
Nickel	0.008
Organic Chemicals (PPM)	
Phenols	0.035

Road Application Techniques

Material Preparation

The first step in road application is to prepare the road surfacing materials properly. Initially all the free bitumen and water mixture in the oil waste ponds is skimmed off and pumped out of the pit. Steam coils have been installed in the oily waste pits to increase heat circulation and enhance the separation of components in the oil waste matrix. The steam and hot water also make the material less viscose, decrease chloride content and assists in adhesion of the oil waste road surfacing material. Removal of the fluid phase of the oil waste is now possible using permanently installed pumps and vacuum trucks. As mentioned previously, it is also possible to recycle the liquids through the plant facilities and add to oil production levels. The remaining oil waste mixture is tested for its chemical composition and if the material is within regulatory specifications it is ready to be used in the road surfacing process. Gravel is also included in the road surface material mix. Gravel is brought to the oily waste pits from borrow areas on the site and is then mixed with the oil waste in the pit. The desired composition depends on the type of road bed and specific quality of the oil waste, but from previous experience a 1:1 mixing ratio of oily waste to gravel has proven most successful. The oil sand road material is now ready for placement. Using a front end loader it is lifted onto trucks and hauled to the road construction work site.

Road Surfacing

The second stage in the oil waste application is the "working in" of the material into the road-way. Wind-rows are made on the road surface by blading loose road bed material into the center of the road and adding available gravel. It is desirable to avoid including topsoil, vegetation, or clay soil into
the wind-row as these materials negatively affect the integrity of the road. It is also important to avoid ripping the road bed with the grader blades as this action will liberate subsurface clay from the road bed and also have a negative affect the integrity of the road-way. Parallel wind-rows are then

completed using these techniques that in essence form a trench between the wind-rows.

When the oil waste material arrives from the pits it is placed in the trench. The actual application rate will depend on the road bed size and oil/gravel characteristics. We have found that a rate of 250 m3 of oil waste mixture per km of road has been effective at CLPP to provide about 0.05 m of elevation to a 9m wide road. Immediately after applying the oily sand the mixture should be graded and dried. The amount of drying depends on the initial water content of the material and the weather conditions at the time of application. Grading and mixing takes place directly behind the unloading truck. The grader then moves the windrows together until both have been combined into a large single row. Then the row is rolled across the road a number of times to ensure that a consistent mixture is obtained and all excess moisture is removed. Attention is then paid to ensuring that the mixture is dried while maintaining the proper consistency. This is achieved most easily in dry weather conditions and with experienced equipment operators. If the mixture does become wet from rain it may take a number of days to complete the rolling and mixing process.

It is critical to pack immediately following the grader leveling. For the best results we have found that packing should be continuous for several days between the oily waste lifts. It is also important to ensure that sufficient packing occurs at the road edges. Further compaction is then accomplished with a grader placing it's blade almost horizontal to the road surface and driving over the road causing surface compression. The final stage of packing consists of using a smooth drum vibrating packer to complete the road-way.

Quality Control

The finished road will be all weather and have a smooth, well compacted surface able to with stand traffic and heavy loads. The road surface is raised to form a "crown" to ensure that runoff is possible. Ditch lines are cleaned after the road is completed to remove debris and excess oil waste. Roads built to these criteria should last for a minimum of two years of normal use without maintenance.

Table 2. Oily waste road application troubleshooting chart.

Road criteria	Description	Indicators
Mixture Quality	Good mixture	- does not stick to tires or boots - no runoff or leaching to landscape - even, dry, consistent road surface
	Too much bitumen	- will puddle - will flow into ditch - appears slick and shiny - will stick to surface of boots & tires - does not roll off grader blades evenly or smoothly - grader and mixers loose traction - vehicles will deform road surface
	Not enough oil (mixture too dry)	- coloration of road surface mixture not consistent - mixture not a dark color (brown, not black) - patches of dry dusty sand or gravel
	Mixture too damp	- no cohesion of mixture - leaching takes place - road surface will break down readily - mixture is dark in color
Compaction	Good compaction	- road surface hard, packed tightly - consistent color - no loose material or free standing liquid - no indents left in road after vehicle traffic passage - should not be able to grind boot heel into surface
	Insufficient compaction	- road edges break after a short period of use - heavy vehicles deform road surface outwards - loose mixture on road surface - ripples develop on road surface

Following several years of experience using oily waste as a road building material Esso personnel have developed a list of common problems to recognize in preparing a sound road-way. Table 2 provides this list as a summary of points to aid in troubleshooting oil waste road construction projects.

Environmental Considerations

From an environmental perspective, there are three important components to the road application of oil wastes. These include; consideration of hazardous chemicals in the oil waste, proper application procedures of the road oiling material, and protection of the environment from run-off from oiled road-ways. The following discussion provides some insight into each of these areas based on experience with road application practices at the Cold Lake Production Project.

In order to avoid the release of hazardous chemicals into the environment it is important to ensure that the oil waste is analyzed for its chemical constituents. At Cold Lake samples are taken from the oil waste pits before each road oiling program is initiated and because we understand the nature of the materials from previous experience the samples are closely scrutinized for pH, chlorides and phenols. We require a Ph from 6.9 to 7.2, a chloride content of under 1000 ppm and phenols under 0.005. If these chemicals are within this acceptable range then the road surfacing material is released to be used in the road application program. It should be noted that at Cold Lake we have observed a large variability in the results of the chemical analyses from the oil waste pit. This can be problematic to the road oiling program as there may be delays caused by inconsistent analyses. Experience has shown that most often the reason for the variation in data is due to the difficulty in obtaining a representative sample at the oil waste pit. The major difficulty in sampling the pits is finding the most appropriate depth in the pit and obtaining a representative sample of both the solid and liquid phase waste material. The joint industry and government task force mentioned previously is currently looking into the sampling problem and has devised an initial sampling guidelines for the petroleum industry that may alleviate this problem.

A second environmental concern relating to road oiling oil wastes involves the assurance that the oil waste on the road-way is an acceptable, non-hazardous material and will not contribute to a pollution incident. As a means to understand the chemistry of the road material used at Cold Lake, four core samples of a completed road-way were taken, batched and analyzed for major chemical constituents. A similar sample of asphalt was also taken for comparative purposes. The results of the analyses are shown in Table 3.

Table 3. Comparative chemical analyses of oil waste road material from Cold Lake.

Parameter	Oil Waste (ppm)	Asphalt (ppm)
Arsenic	0.04	0.10
Boron	0.1	0.38
Cadmium	0.001	0.01
Chromium	0.6	0.16
Lead	0.057	0.63
Zinc	0.14	0.99
Mercury	0.0001	0.0001
Selenium	0.0017	0.0002
Barium	0.55	2.80
Copper	0.06	0.36
Phenol	0.035	0.024

The data suggest that the levels of the parameters measured were at most often lower in the oil waste samples than in the Asphalt samples. The pH of both asphalt and oil waste samples averaged 7.2 at which point most of these metals are not mobile (3). The phenol content in the oil waste sample

was recorded at a slightly higher level than the asphalt indicating a liberation of these materials in that particular sample.

These types of tests are important to preform in oil waste road disposal programs as they provide a basis for evaluating the environmental impact of the program.

An important environmental concern regarding road oiling is that of run-off contamination of soils caused from road oiling programs. The environmental impact of oil to soil is well understood and documented from a physical and chemical perspective (4,5,6,). Briefly stated, the hydrocarbon component, if in a sufficient quantity can impact the microbiological populations in the soils and also alter the chemical balance of the soil matrix. Further, if chemicals reach high enough levels, toxicity to vegetation may occur.

Samples have been taken from the ditch surrounding the road-way following road application at Cold lake. The samples consisted of cores and were batched and analyzed for the chemical make-up. The results of the analysis is provided in Table 4.

Table 4. Results of soil samples adjacent to oil waste road-ways

Parameter	Value (mg/kg) *
pH	8.2
Chlorides	42.67
NO_3	39.67
SO_4	41.00
Mg	38.33
CA	103.67
NA	81.00
K	11.33
SAR	1.73

*Average of three grab samples

Parameters of particular concern are those that could affect the nutrient exchange capacity of the soil such as essential nutrient levels and sodicity (SAR). Additionally, salt build-up that may contribute to potential toxicity is very important and is measured by chloride content. The results of these samples show clearly that following careful road application techniques there is no evidence of elevated levels of the chemical parameters.

As a final point on environmental considerations in road oil application, special environmental needs arise when application procedures are carried out in wet conditions. Precautions to protect sensitive areas such as water courses from excessive run-off are required. Wind-rows are doubled, and placed at the high side of the road bed to prevent water from running off. If run-off accumulates it will require collection and removal with a vacuum truck. During these conditions at Cold Lake constant observation and monitoring for a "no sheen" (no oil) run-off is carried out.

Conclusion

Experience and experimentation at Cold Lake have resulted in the development of an oil waste road application technology that provides a cost effective, environmentally sound solution to a waste disposal problem. Roads surfaced with oil waste at Cold Lake are high quality, all weather roads capable of handling traffic exceeding 400 vehicles per day and loads up to 35 tonnes.

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ONSHORE SOLID WASTE MANAGEMENT IN EXPLORATION AND PRODUCTION OPERATIONS

Introduction

The American Petroleum Institute (API) initiated a project in 1988 to develop environmental guidelines for management of solid waste in oil and gas exploration and production (E&P) operations.

As a result of this effort, API published its Environmental Guidance Document in January, 1989.

The document provides guidance for management of drilling fluids, produced waters, and other wastes associated with E&P primary field operations:

1) gas plants,
2) field facilities,
3) drilling, and
4) workovers.

The following paper describes the content and recommendations contained in the API document and its use as a tool for environmentally sound management of exploration and production wastes. Also included is information on how the document is being used and can be used for environmental training within the oil and gas industry.

Background

The federal government's increasing interest in potential environmental and human health impacts associated with exploration and production of crude oil and natural gas arose from a two-year study of E&P waste and their associated waste management practices by the Environmental Protection Agency (EPA) in 1986 and 1987. The results of that study were documented in a December 1987 Report to Congress, which was required by the 1980 amendments to the federal Resource Conservation and Recovery Act (RCRA) which requires EPA to regulate the management of solid waste. Based on findings of its Report to Congress, oral testimony and written comments received during public hearings in the spring and summer of 1988, EPA, on June 30, 1988, decided not to recommend to Congress federal regulation of E&P wastes as hazardous wastes under Subtitle C of RCRA.

EPA's June 30, 1988 Regulatory Determination did state EPA's intent to promulgate tailored criteria for nonhazardous waste management of exploration and production wastes. Existing RCRA Subtitle D regulations for nonhazardous wastes establish minimum federal criteria and require states to submit solid waste management plans for EPA approval. The Regulatory Determination called for a three-pronged approach aimed at filling "gaps" in existing State and Federal regulatory programs by:

1) "Improving Federal programs under existing authorities in Subtitle D of RCRA, the Clean Water Act, and Safe Drinking Water Act;
2) Working with States to encourage changes in their regulations and enforcement to improve some programs; and,
3) Working with the Congress to develop any additional statutory authority that may be required."

The API prepared its Environmental Guidance Document to support EPA's activities by providing guidance to industry and regulatory agencies by;

1) Defining environmentally-sound operating and waste management practices;
2) Identifying conditions and areas where these practices are appropriate;
3) Supporting development by state agencies of area or statewide waste management plans required by RCRA based on these practices; and,
4) Describing how these plans should be prepared, including a suggested outline of their contents.

The basic premise of API's approach is the development by state regulatory agencies of formal plans based on environmentally-sound waste management practices.

Area or statewide plans are endorsed because the exploration and production of oil and gas is conducted in a wide variety of environmental settings, making nationwide standards impractical. Fundamental differences exist from state to state, and within regions within a state, in terms of climate, hydrology, geology, economics and method of operations which impact the manner in which oil and gas exploration, development and production is performed. The recommended waste management plans should encompass all wastes that will be generated and addresses factors such as surface and subsurface geology as well as meteorological conditions. Provisions should be included for state approved site specific plans where deviation from standard practices are justified by special or unusual circumstances. In these instances, state regulatory agencies should ensure that alternate procedures are equally protective of the environment.

API does not recommend that redundant or duplicate regulations be developed in states where adequate protective measures currently exist and are being enforced. API does endorse the enforcement of all existing state and federal plans, regulations, and requirements and believes these should form the basic building blocks of the non-hazardous waste management plans required by RCRA.

The intent of the Environmental Guidance Document is also to aid in explaining pertinent facts of exploration and production operations to the public and government agencies, and to assist in identifying major environmental legislation and their associated regulatory programs governing E&P waste management.

It is the intention of API to update its Environmental Guidance Document periodically as new scientific information becomes available concerning the waste management and disposal practices discussed, and as new practices are identified. Cooperative efforts between federal and state regulatory agencies, industry and other interested parties are expected to continue generating much useful information in this area over the next several years.

Following is a discussion of the content of API's Environmental Guidance Document.

Section 1: Summary of Environmental Regulations

The first section of the Environmental Guidance Document summarizes the large body of federal, state, local and lease statues and regulations pertaining to E&P waste management and disposal practices. These requirements impose responsibility and liability for protection of human health and the environment from harmful waste management practices or discharges. The following specific statutory and regulatory requirements are summarized in Section 1:

- The Resource Conservation and Recovery Act
- The Safe Drinking Water Act
- The Clean Water Act
- The Comprehensive Environmental Response, Compensation, and Liability Act
- Federal Land Management Regulations
- State Environmental Performance Regulations
- Oil and Gas Lease Agreements

Section 2: The E&P Exemption from RCRA Subtitle C Regulations

Congress recognized the special nature of oil and gas E&P wastes, and exempted them from hazardous waste regulation under RCRA Subtitle C, subject to the previously discussed EPA study. This study, and the June, 1988 Regulatory Determination that followed, concluded the exemption is appropriate and should be continued for E&P wastes associated with primary field operations.

The Environmental Guidance Document describes EPA's hazardous waste criteria, provides EPA's definition of solid waste and identifies wastes that have been designated by EPA as exempt and nonexempt from hazardous waste management requirements. A discussion of the methodology EPA used in developing its lists is included as well as these methodologies applicability to wastes not specifically addressed by EPA. Section 2 also addresses the manner in which these definitions can complicate management and disposal of nonexempt wastes.

In simplest terms, a solid waste is any material that is discarded or intended to be discarded. According to RCRA, solid wastes may be either solid, semi-solid, liquid, or contained gaseous material.

Specifically excluded are point source discharges subject to NPDES permits under the Clean Water Act. EPA has also determined that produced water injected for enhanced recovery is not a waste for purposes of RCRA Subtitle C or D, since produced water used in enhanced recovery is beneficially recycled as an integral part of some crude oil and natural gas production processes. Commercial products are also not wastes unless and until they are discarded.

The Environmental Guidance Document addresses in depth those waste management practices that are unique to E&P operations and wastes that were determined by EPA to be exempt from the hazardous waste management requirements of Subtitle C of RCRA. These wastes include drilling muds and cuttings, produced water and associated waste. Waste management practices that are uniformly regulated by RCRA hazardous waste management requirements as well as management of general industrial wastes such as solvents, off-specification chemical, commercial products, household wastes and office refuse are not addressed by these criteria.

These criteria also do not address disposal of produced water by injection or surface discharge -- waste management practices that are regulated by EPA or by the states under authority of the federal Safe Drinking Water Act and federal Clean Water Act, respectively. Disposal of produced water in pits, by land application or commercial disposal facilities is addressed.

For perspective, nearly 21 billion barrels of produced water -- or 98 percent of all E&P wastes -- were generated in the U.S. in 1985, according to API figures. Most of that produced water was disposed by injection, with much smaller volumes discharged to surface waters or disposed in pits, by land application or commercial disposal facilities. Drilling wastes (i.e., drilling fluids and cuttings) accounted for about two percent of all E&P wastes generated in 1985, totaling 361 million barrels.

Many nonexempt wastes are generated during maintenance of production equipment as well as transportation (pipeline and trucking) activities. These wastes, while nonexempt, are not necessarily hazardous. They are subject to the same provisions as any other industrial or municipal waste. The general provisions of testing whenever there is reason to believe nonexempt waste may exhibit a hazardous waste characteristic, the prudence of segregating non-exempt waste from exempt waste, and special requirements posed if these wastes are not segregated or tested prior to mixing with exempt waste are discussed in the Environmental Guidance Document.

Section 3: Wastes Generated in E&P Operations

Section 3 of the Environmental Guidance Document discusses the four activities associated with primary E&P operations: gas plants, production facilities, drilling and workover operations. It discusses operational and design aspects of E&P equipment and processes

as well as the wastes generated. Companies differ in their engineering design and operational practices, but they generally all utilize elements of the technology discussed and generate the wastes discussed in this section.

Natural gas plants provide centralized dehydration, compression or sweetening facilities necessary to place natural gas in marketable condition and to extract natural gas liquids such as ethane, propane and butane. Individual wastes generated in the five extraction and treatment processes performed in gas plants are listed and discussed. The five processes are:

1) Inlet separation and compression where wastes generated include produced water, pigging materials, inlet filter media, corrosion treatment fluids and small amounts of solid material such as pipe scale, rust and reservoir formations materials.
2) Dehydration processes necessary to remove the water vapor present in all natural gas to pipeline specifications. Wastes include glycol based fluids, glycol filters, condensed water and solid desiccants.
3) Sweetening/sulfur recovery wastes from process steps necessary to remove naturally occurring impurities such as hydrogen sulfide or carbon dioxide contained in natural gas to meet specifications for sales pipelines. Wastes include spent amine, used filter media, spent iron sponge, spent caustic solution, spent catalyst and molecular sieve.
4) Natural gas liquid recovery process wastes including spent absorption oils, waste waters and boiler blowdown waters.
5) Compression and plant utility operations necessary to operate and maintain gas plant processing equipment where wastes largely consist of nonexempt waste material such as used oils, rags, sorbents and equipment filters.

Waste generated from field facilities and descriptions of the facilities generating these wastes are also described in Section 3. Field facilities include equipment used to collect oil and gas from the well and to prepare it for sale. Well fluids are often a complex mixture of liquid hydrocarbons, gas water and solids. A primary function of the production process is to separate the constituents of the mixture and remove those that are not merchantable to meet purchaser standards.

Wastes generated from the following field facilities in the production process are described: wells, flow lines, separators, free water knockouts, heater treaters/electrostatic treaters, oil stock tanks, NPDES produced water discharges, centrifugal desanders, produced water tanks, filters, gas flotation vessels, produced water injection systems, steam generators and associated water softening facilities, compressors, dehydration and sweetening units, produced gas and fuel gas scrubbers, methanol injection and line heaters and drilling operations.

Section 4: Environmental Guidance for Waste Management By Waste

Section 4 of the Environmental Guidance Document provides guidelines for the management of production wastes in an environmentally sound manner. Although special circumstances may exist warranting regulatory approval of other specific practices, waste management should generally adhere to the criteria described in this section.

Due to operators' limited control over wastes received and financial viability of commercial facilities that may lead to CERCLA, corrective action requirements under RCRA or other liabilities, it is recommended that operators minimize potential liabilities associated with offsite waste disposal by keeping records of types, volumes, analytical data, destination, and haulers of waste fluids transported to offsite facilities. It is also recommended operators periodically inspect offsite facilities used.

Section 4 also describes the physical properties of concern with management of specific wastes and describes applicable practices for produced water, drilling waste, reserve pit waste, drilling rig waste, workover and completion waste, tank bottoms, emulsions, heavy hydrocarbons, contaminated soils, used oils and solvents, dehydration and sweetening waste, oily debris and filter media, gas plant process and sulfur recovery waste, cooling tower blowdown, boiler water, scrubber liquids, steam generator waste, plus downhole and equipment scale.

Section 5: Environmental Guidance for Waste Management and Disposal By Practice

Section 5 describes available waste management practices for E&P wastes. It describes these practices, their potential environmental impacts and the waste and waste characteristics for which they are appropriate. Although special circumstances may exist warranting regulatory approval of other specific practices, management of wastes should generally adhere to these criteria.

As in any aspect of waste management, there are some general, sound practices that should be employed. These sound practices not only serve to protect human health and the environment, but also tend to protect an operator from long term liabilities associated with waste disposal. As a general rule-of-thumb, the choice of a waste management option would be based upon the following hierarchy of preference:

1) Source Reduction - reduce the quantity or relative toxicity of waste generated;
2) Recycling - reuse or reclaim as much of the waste generated as possible;
3) Treatment - employ techniques to reduce the volume or the relative toxicity of waste that has been unavoidably generated;

4) Proper Disposal - utilize environmentally-sound methods to place waste generated into the environment in a way that minimizes its impact and protects human health.

Viewed in this manner, the following general guidelines should be followed:

1) Check all applicable regulations (federal, state and local) and lease provisions;
2) Consider notifying the landowner and state agency with authority over the waste or practice;
3) Consider the likely fate of the waste and its constituents over the long term;
4) When wastes are disposed in offsite commercial facilities, keep records that document the type and quantity of the waste, method of disposal, location of disposal, date of disposal, and any other pertinent information that could prove useful in subsequent investigations to assess liability.

Waste minimization means the reduction, to the extent practical, of the volume or relative toxicity of liquid or solid wastes that are generated and subsequently treated and require disposal. Waste minimization focuses on source reduction, recycling, and beneficial treatment to allow for reuse.

Opportunities to achieve significant waste volume reductions in exploration and production operations are limited because E&P waste volumes are primarily a function of activity level and age or state of depletion of a producing property. For example, the volume of produced water and associated emulsions, number of workovers, fluid handling equipment, etc. typically increases as fields deplete. Also, the volume of drilling muds generated is generally a function of the number of wells drilled and their depth. Thus, the waste minimization method with the greatest potential benefit is onsite recycling of hydrocarbons including waste oils, hydraulic fluids, oily sump waters, etc. Recovery of hydrocarbons from tank bottoms and separator sludges can be accomplished at onsite production facilities or offsite commercial facilities. Oil-based drilling mud should be returned to the vendor for reprocessing where practical. Other than onsite recycling, the most promising application of this concept is through thoughtfully developed area waste management plans which can incorporate locally available recycling capabilities and facilities in addition to accounting for chemical product availability.

Waste management criteria are discussed for roadspreading, burial or landfill, onsite pits including reserve pit construction, operation and closure, production pits including blowdown and emergency pits, workover pits, basic sediment pits, percolation pits, unlined skimming or settling pits, produced water pits, evaporation pits, annular injection of reserve pit fluids, underground injection wells, NPDES discharges, open burning and incineration and offsite commercial facilities.

Section 6: Guidelines for Developing Area Specific Waste Management Plans

Section 6 of the Environmental Guidance Document contains guidelines for developing area-specific waste management plans followed by an example plan required by the California Waste Management Board for oil field operations in Kern County.

This section recognizes that because the Environmental Guidance Documents provides a national baseline or standard of performance, it requires translation into regional or area plans to be useful to operators for their day to day operations. A generalized methodology for this transformation is included in this section.

API Communication Activities

With completion of the Environmental Guidance Document in 1989, API commenced an extensive communications program to publicize and encourage use of the document.

The Environmental Guidance Document was initially distributed to all E&P members of API and bulletins were sent to local API chapter organizations who were offered speakers and encouraged to make its presentation the subject of a local chapter meeting. Many chapters incorporated these presentations into meetings centered on environmental protection.

Copies and speakers were provided for regional trade association meetings in Texas, Oklahoma, Michigan, Wyoming, Colorado, Louisiana and Kansas.

The document was publicized by the Independent Producers Association of America and made available to its members at no cost.

Presentations were also made to the EPA, Department of Energy (DOE), Congressional staff, the Interstate Oil Compact Commission, numerous state oil and gas regulatory agencies and copies furnished national environmental organizations.

To date, over 5000 copies have been distributed.

Usage of The Environmental Guidance Document

Evidence of Environmental Guidance Document usage has occurred by incorporation as a basis or reference by state oil and gas agencies in modifying their regulatory frameworks, usage by the Interstate Oil Compact Commission as a reference in its regulatory work for the EPA and usage by a number of operators in development of environmental training and auditing programs.

In the area of audit programs, the Environmental Guidance Document has provided a starting point for training and assessing compliance with federal, state and local laws and regulations in addition to quantifying API environmental policies and principles endorsed by all member companies. The Environmental Guidance Document has accomplished this by:

1) Providing management and line personnel education, a training plan and basis for improved communications between all levels regarding performance expectations.
2) Identifying and dealing with potential outstanding compliance issues and improving environmental practices.
3) Increasing management and regulatory staff involvement in day to day environmental activities.
4) Identifying information to be collected and maintained useful in assessing potential impacts of environmental performance and developing legislative and regulatory initiatives.
5) Developing baselines for continuous improvement in environmental practices and performance.

In addition, numerous operators have translated the Environmental Guidance Document into regional drilling or production facility waste management manuals or plans including specific wastes, practices and disposal sites allowed to be used by their company personnel or in inspection criteria to be used for disposal sites. API has also charged its E&P training committee with responsibility to develop a workshop to be held for operators and recorded on videotape covering how to develop these individualized plans.

Plans for Revision

API recognizes the need to keep the Environmental Guidance Document evergreen and build upon the experience of user and regulatory groups. To this end, a survey of these groups was made and ideas for improvement solicited from EPA, state regulatory agencies, operators, and national environmental organizations. Following are areas that may be included in an update targeted for publication in 1991:

- A consistency review with the IOCC Committee on Regulatory Needs Report establishing regulatory technical and administrative criteria for E&P waste management programs.
- An expanded waste minimization section
- Guidelines for field sampling and analysis of oil field wastes
- A description of EPA's revised hazardous waste toxicity characteristic (TC) and associated laboratory test (TCLP) including compliance guidance
- Naturally occurring radioactive material management guidelines
- Incorporation of land disposal criteria for metals
- Incorporation of land disposal criteria documentation for salt, hydrocarbon and pH

- Expanded criteria for annular disposal of drilling muds
- Training guidelines for development of area waste management plans to translate the general national criteria into site specific plans
- Development of waste management facility environmental audit practices and checklists
- Expanded waste characterization activities

To date, the following work has been completed and is available from API:

1) API Production Bulletin - Evaluation of Limiting Constituents Suggested for Land Disposal of E&P Wastes by L. E. Deuel. This bulletin contains criteria for salt, hydrocarbons and pH.

2) Guidance on interpretation and compliance with the current EPA hazardous waste toxicity test.

The remainder of the work is underway and should be completed in 1991.

Longer term development of a corrective action section dealing with site and spill remediation levels, procedures and technology has been approved and a work plan is presently under development.

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AN OVERVIEW OF PRODUCED BRINE INJECTION PRACTICES IN KENTUCKY

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The U.S. Environmental Protection Agency (EPA), Office of Drinking Water, is responsible for regulating the Underground Injection Control (UIC) Program. The program was authorized by Congress in the Safe Drinking Water Act (SDWA) to protect the underground sources of drinking water (USDW). Five classes of injection wells are regulated by the UIC program. Well classification is based on the type of fluid injected and the relationship between the injection zone and the lowermost underground source of drinking water. Class II wells are used to inject fluids associated with the production of oil and gas or fluids and compounds used for enhanced hydrocarbon recovery. These wells normally inject below the deepest USDW except in cases where the USDW contains producible quantities of oil and gas. Class II wells are classified II-D if they are disposal wells or II-R if they are enhanced recovery wells.

Approximately 6000 Class II injection wells exist in Kentucky. The majority of these wells are operated in conjunction with stripper well production in mature fields. Brine production has steadily increased over time while oil production has decreased. Disposing of this brine in a legal and cost effective way has been critical to the continued operation of these fields. Prior to the passage of several environmental acts, namely the Clean Water Act and the Safe Drinking Water Act, the disposal of brine in Kentucky was virtually unregulated. Surface discharge of brine into streams, injection of brine into sinkholes and using unlined evaporation pits were all common practices. In fields where injection wells were being used, the construction of the well and the injection operation was unregulated. With the new environmental programs being strictly enforced, operators have been forced to use injection wells to dispose of their brine in a legal and environmentally safe manner or shut-in production.

The UIC regulations are multi-faceted. Along with defining the regulatory framework for the Federal and State programs, the regulations set forth technical criteria and standards for injection wells. This portion of the program has had the largest impact on the Kentucky oil and gas industry. EPA, Region IV, responsible for administering the UIC program in Kentucky, has issued several guidance documents in order to clarify its position on minimum acceptable construction standards that will provide protection against contamination of USDW's by Class II wells. Documents outlining casing and cementing, plugging and abandonment and financial responsibility requirements have been developed and distributed to operators of injection wells. A series of outreach programs were held in Kentucky to explain the UIC regulations to the operators. Field inspectors held public meetings and met with individual operators to discuss problems related to injection wells. UIC permit writers gave seminars on how to obtain a UIC injection permit and have developed alternatives to corrective action requirements for wells in the area of review. As a result of this ongoing interaction between the EPA and the oil industry in Kentucky, the injection of brine into properly constructed wells has become an environmentally safe and effective way to dispose of this oil field waste.

AN OVERVIEW OF TREATMENT TECHNOLOGIES FOR REDUCTION OF HYDROCARBON LEVELS IN DRILL CUTTINGS WASTES

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Introduction

Drill cuttings are one of the major wastes associated with oil and gas drilling operations. When oil-based drilling fluids are used for drilling operations, the drill cuttings become contaminated with substantial amounts of hydrocarbon material and may require treatment prior to disposal, whether disposal is to surface waters or at an approved land disposal site. This paper presents an overview of some recently developed treatment technologies for the reduction of the hydrocarbon levels in the drill cuttings. It will generally acquaint the reader with some of the basic technologies and treatment performance capabilities. However, it is not intended to provide in-depth coverage of the design and operation of the technologies. This paper also highlights some environmental, cost, energy, maintenance, and safety aspects which should be considered in the design and operation of such systems.

The separation of drill cuttings from drilling fluids is typically accomplished using mechanical apparatus such as shale shakers, hydrocyclones, and centrifuges. Such equipment can produce either continuous or intermittent discharges of hydrocarbon-laden drill cuttings. However, substantial amounts of hydrocarbon and drilling fluids can remain with the drill cuttings after this type of mechanical separation. Typically, the drill cuttings contain about 20 weight percent of hydrocarbon.

Opinions, conclusions and recommendations presented in this paper are solely those of the authors and are not to be construed as U.S. EPA policy. Mention of trademarks, trade names, and patented processes does not constitute endorsement by the U.S. EPA.

Current Technology

Historically, hydrocarbon-laden drill cuttings were either disposed at the drilling site (whether discharged to surface waters or stored and disposed in pits) or, where required, were treated using cuttings washer technologies prior to disposal. Cuttings washers use either high pressure water sprays or immersion of the cuttings with agitation in a vessel with water and detergent to remove the hydrocarbon and drilling fluid. The cuttings washer technologies typically reduce the hydrocarbon content from about 20 weight percent to about 10 weight percent of residual hydrocarbon on the cuttings. Most of the cuttings washer vendors claimed that the discharge to surface waters of cuttings treated by washers would result in no visible sheen, which is EPA's indicator of "no discharge of free oil" to surface waters. However, few if any of the vendors appear to still be in the business of supplying cuttings washers. This is due partly to the inability of the technology to achieve sufficiently low levels of residual hydrocarbon and also because of waste management problems associated with the resulting water/detergent/hydrocarbon solutions.

New Technologies

Newer technologies for reducing the hydrocarbon content of drill cuttings are being developed by several commercial vendors. The remainder of this paper describes to the reader two general classes of these newer technologies -- thermal processes and solvent extraction processes.

Thermal Processes

Thermal processes use a temperature- and air-controlled, thermal distillation step to vaporize water and hydrocarbon from cuttings. This may by followed by an oxidation or combustion step to achieve additional hydrocarbon removal. The thermal distillation process exposes the cuttings to controlled heat sufficient to vaporize the residual hydrocarbon and water. The hydrocarbon and water vapors are then condensed and either disposed or they may be reused in drilling fluid systems. If an oxidation step is used, the cuttings are subjected to a second pass of controlled heat and air to combust additonal residual hydrocarbon. The treated cuttings are reduced in volume and emerge from the process as a relatively dry granular or clay-like material.

Following are descriptions of some of the systems available from vendors that use thermal processes.

Thermal Process 1 - Electrical Thermal Distillation

Thermal Process 1 treats drill cuttings in a continuous mode to remove hydrocarbon material with the processed cuttings reportedly suitable for discharge to surface waters or disposal at a land disposal site. The drill cuttings are exposed to controlled heat generated by electric resistance heaters that is sufficient to vaporize residual hydrocarbon and any water on the cuttings. The processed cuttings are dry and granular in appearance. The water and hydrocarbon vapors and off gases are carried from the process chamber by nitrogen gas. They are directed to a water-cooled condenser and the condensed water and hydrocarbon are then separated. The hydrocarbon may be suitable for return to the drilling fluid system if it meets the drilling operator's specification for hydrocarbon additives. The condensed water is discharged if it meets the appropriate discharge standards. Non-condensables and off-gases from the unit are passed through an activated carbon filter and then vented to the atmosphere. The processing units are provided in a skid-mounted configuration. A schematic diagram of the this type of thermal system is presented in Figure 1.

The process efficiency of the unit is reported by the vendor to be superior to cuttings washers. A field sampling program was performed for the EPA on a full-sized unit to obtain data on the residual hydrocarbon content of the drill cuttings treated by this process. The results of the sampling program indicated that the untreated drill cuttings had a hydrocarbon content ranging from 5.1 to 8.7 weight percent and the treated cuttings contained from 0.23 percent to 3.8 weight percent of residual hydrocarbon.

The estimated cost for this system based on equipment rental for a 35 day drilling campaign and operating 24 hours per day is approximately $165,000 (1988 dollars). This estimate includes equipment rental, operating labor, energy requirements, and setup and teardown expenses. If the unit is to be used at an offshore platform, the cost would increase by approximately $10,000 to cover the equipment and personnel transportation costs, platform living expenses for operating personnel, and shore support.

Thermal Process 2 - Thermal Energy Distillation

Thermal Process 2 is a process for the continuous treatment of drill cuttings and recovery of hydrocarbon. The raw cuttings are routed to the drying section of the process unit where water and hydrocarbon are driven off by thermal energy from an

external heat supply. The unit providing the external heat can be fired by waste oil, diesel oil or natural gas. The water and hydrocarbon vapors that are driven from the cuttings are passed through water-cooled condensers. The resultant condensate is directed to a separator to separate the hydrocarbon from the water. The hydrocarbon is placed in storage for reuse or for further processing, if required. The water, still containing substantial amounts of finely divided oil in suspension, is passed through a two-phase process to effect additional separation of hydrocarbon from the water. The unit is skid mounted for use both onshore or at offshore operations either on a mobile drilling unit, platform or barge. This process is shown schematically in Figure 2.

According to the manufacturer, a prototype demonstrator unit has achieved residual hydrocarbon levels in drill cuttings of less than 0.5 weight percent.

Using the prior example of 35 operating days and 24 hours per day operation, the estimated cost on a rental basis for this system is about $80,000 (1988 dollars). This estimate includes equipment rental, operating labor, energy requirements, and setup and teardown expenses. If the unit is to be used at an offshore platform, the cost would increase by approximately $10,000 to cover the equipment and personnel transportation costs, platform living expenses for operating personnel, and shore support.

Thermal Process 3 - Indirect Thermal Distillation

Thermal Process 3 is a continuous thermal distillation process that uses an external heat source to provide indirect heat for hydrocarbon and water removal. Cuttings are fed to a blender where a homogenous slurry is made by the addition of water to the cuttings. The added water facilitates handling of the cuttings feed stream to the system. The slurry is fed to a jacketed processing vessel. During normal drilling operations, the blender accumulates the solids and the processing unit needs to operate only about half of the time. A closed liquid heat transfer system circulates hot oil around the processing unit to provide the indirect heat to drive the water and hydrocarbon from the cuttings. The heating oil does not contact the materials being treated. On land locations, the heat required for this process is provided by an oil heating unit. The hydrocarbon and water vaporized from the cuttings are condensed and recovered. At offshore installations the heat source can be waste heat that is recovered from the rig generator exhaust. This system reportedly produces a dry, free flowing solid, free of visible

THERMAL PROCESS 1
SCHEMATIC FLOW DIAGRAM

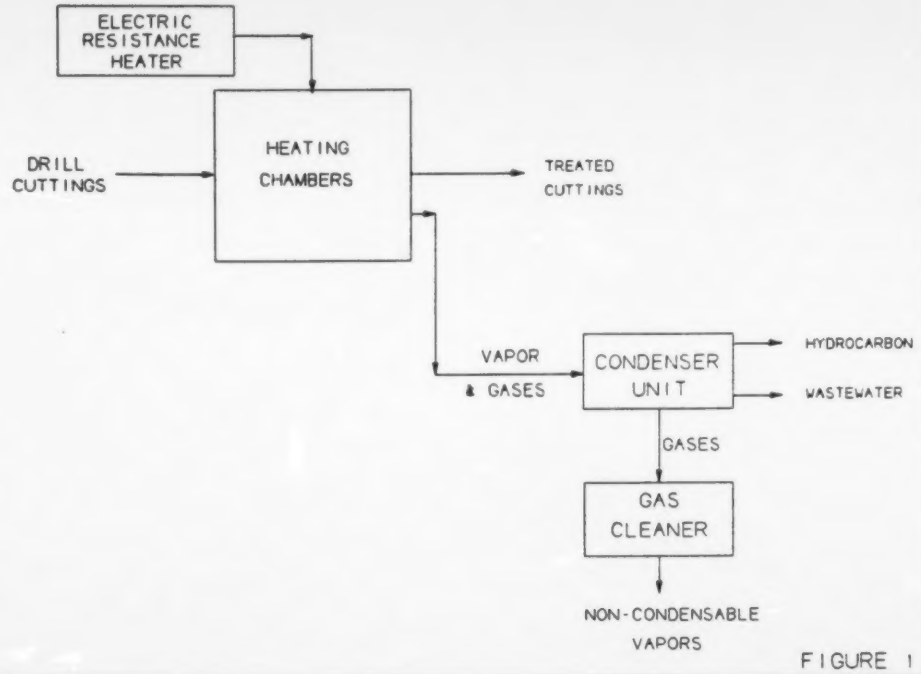

FIGURE 1

THERMAL PROCESS 2
SCHEMATIC FLOW DIAGRAM

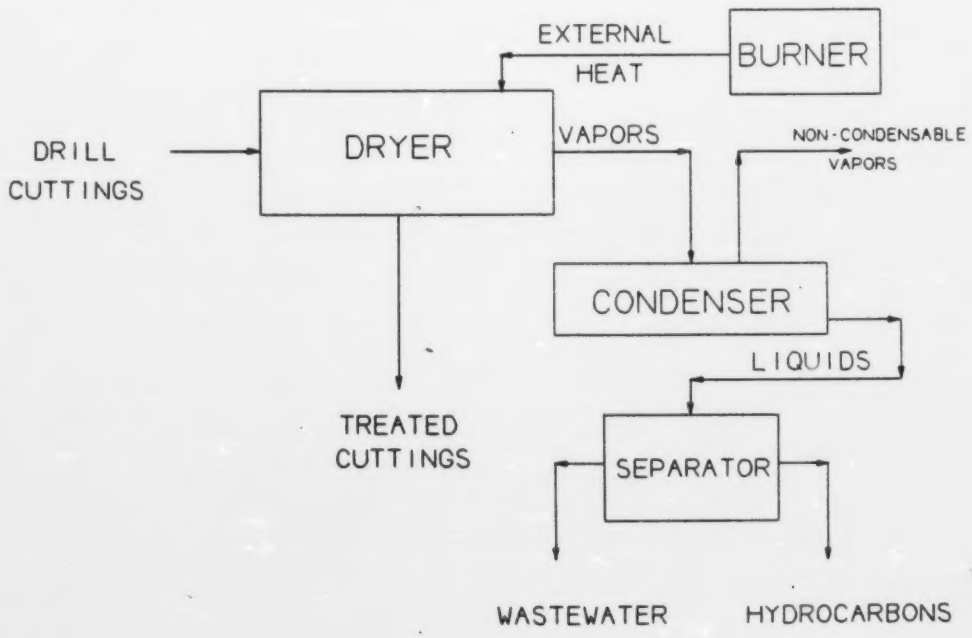

FIGURE 2

hydrocarbon. A schematic diagram of the system is presented in Figure 3. The system is supplied in a skid mounted configuration.

Results from tests on a pilot-plant scale by the manufacturer indicate that the process can achieve a residual hydrocarbon content of 6 weight percent or less on the treated cuttings.

Due to incomplete information being available at this time, a current cost estimate for this system was not made.

Solvent Extraction Processes

Solvent extraction technology uses a solvent to extract the hydrocarbon from the cuttings. Extracted hydrocarbon material is separated from the solvent and either disposed or recycled. The treated cuttings emerge from these processes in a relatively dry granular form. Following are general descriptions of solvent extraction systems which have been constructed and tested by manufacturers.

Solvent Extraction Process 1 - Dual Stage

Solvent Extraction Process 1 is a continuous solvent extraction system using CFC-123 (dichlorotrifluoroethane) as the solvent. The drill cuttings are first slurried in a fluidizing holding tank with oil or water, depending on the application, to facilitate pumping of the cuttings. The slurried cuttings are fed to the first of two extractor units where the slurry is contacted with the solvent. The mixture is then directed to a hydrocyclone where the solvent and the cuttings are separated. The hydrocarbon-solvent mixture is sent to the solvent and oil separation system. The cuttings are then directed to the second extraction unit where clean solvent is contacted with the cuttings. The mixture from the second extraction unit is directed to a second hydrocyclone for separation of the cuttings and solvent. The liquid mixture removed by the second hydrocyclone is directed to the first extraction unit and the treated drill cuttings are sent to a drying system. The solvent and hydrocarbon separation system consists of an extractor and a separation column where the hydrocarbon, water and solvent are separated. The hydrocarbon phase flows to the fluidizing holding tank and the solvent is recycled to the second extraction unit. The manufacturer reports that the system is completely closed to preclude vapor emissions to the atmosphere. This process, which is skid mounted, is shown schematically in Figure 4.

The manufacturer indicates that the system is designed to

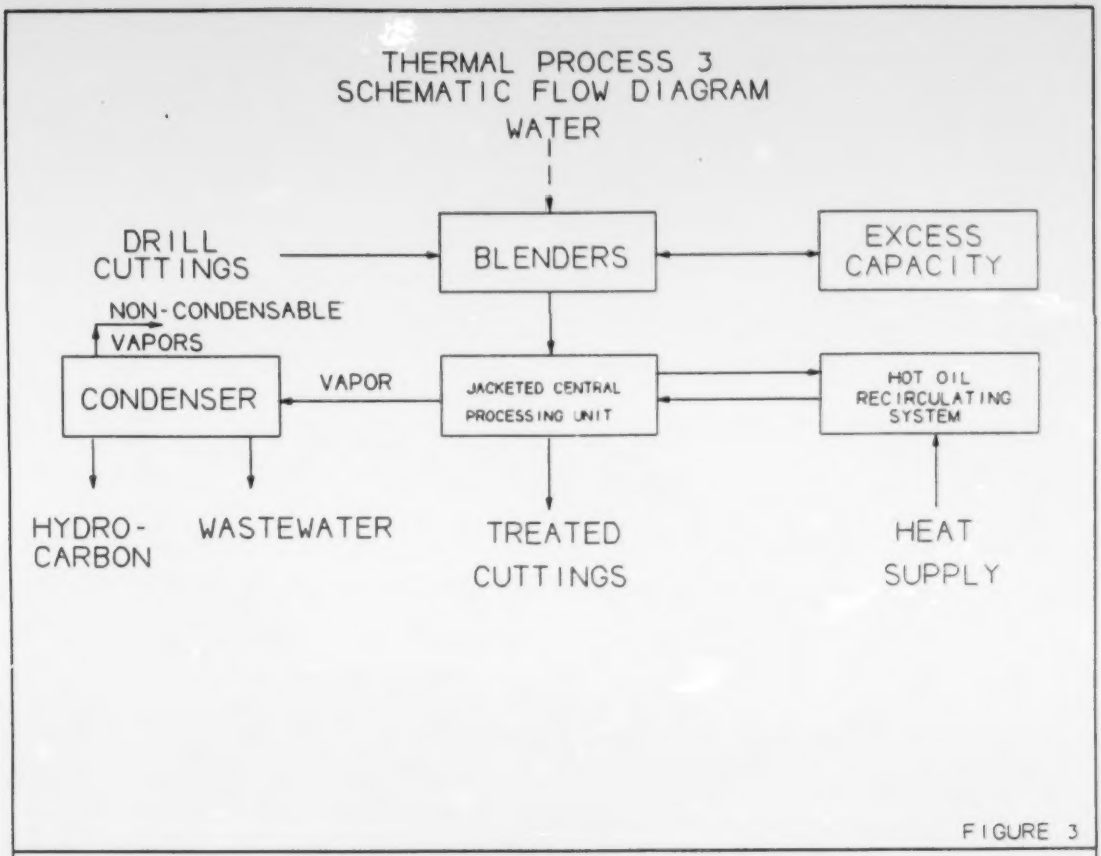

FIGURE 3

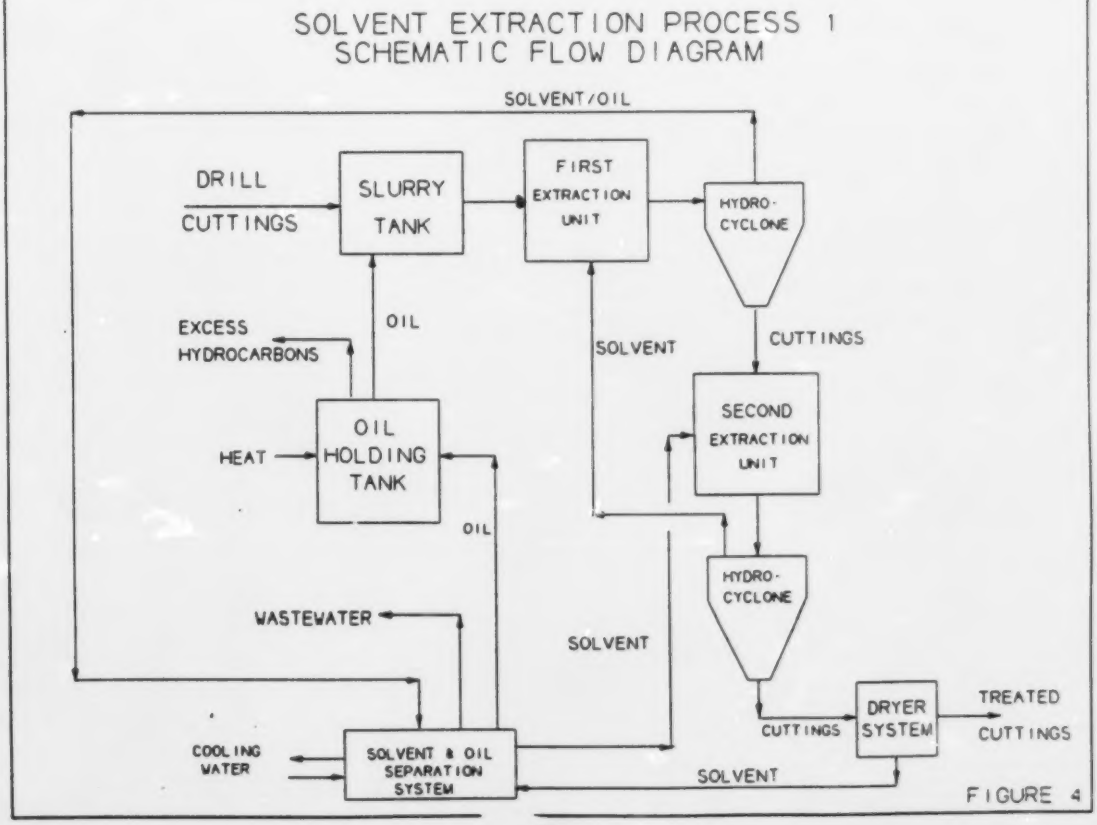

FIGURE 4

operate on an around-the-clock basis. However, it could be operated in an intermittent mode with a short time required for start-up and shutdown. The process is designed to treat drill cuttings to achieve a hydrocarbon level of less than 0.8 weight percent. This technology has been tested on drill cuttings although it has not yet been applied on a full-scale basis for treating drill cuttings. This technology has been applied on a full-scale basis for the treatment of oily steel mill scale and various petroleum refinery slop oils, sludges, and tank bottoms (EPA hazardous waste numbers K048 through K052, Code of Federal Regulations, Title 40, section 261.32).

The manufacturer reports that approximately 99.92 percent of the solvent is recovered. The manufacturer reports that the capital cost of the system is between $1,600,000 and $2,500,000 (1990 dollars) and would require one operator per shift. This cost includes all equipment, materials, piping and valves, electrical design, engineering design and fabrication, and process warranty fees. Land installation including engineering, labor, and materials costs an additional $250,000 (1990 dollars.)

Solvent Extraction Process 2 - Closed Loop

Solvent Extraction Process 2 is a closed loop, continuous solvent extraction system. This process operates at essentially atmospheric pressure and temperature and uses a non-flammable, chlorinated hydrocarbon solvent. The process has three separate subsystems -- cutting feed system, extraction system and solvent recovery system. Each subsystem is individually skid mounted.

The cuttings feed system is an integral part of a proprietary extraction system and could be installed on the extraction skid. However, to provide flexibility to the drilling operator, it is provided on a separate skid. The cuttings feed skid contains some feed surge capacity and a means of transporting the cuttings to the extraction system.

After use, the solvent is pumped from the extraction system to the solvent recovery system where it is separated into solvent, hydrocarbon, and water fractions using distillation technology. Clean solvent is recycled to the solvent extraction system and hydrocarbon may be returned to the drilling fluid system. Reportedly, the water fraction from the solvent recovery system is suitable for discharge. A schematic diagram of this system is presented in Figure 5.

According to the manufacturer, this system can clean cuttings

SOLVENT EXTRACTION PROCESS 2
SCHEMATIC FLOW DIAGRAM

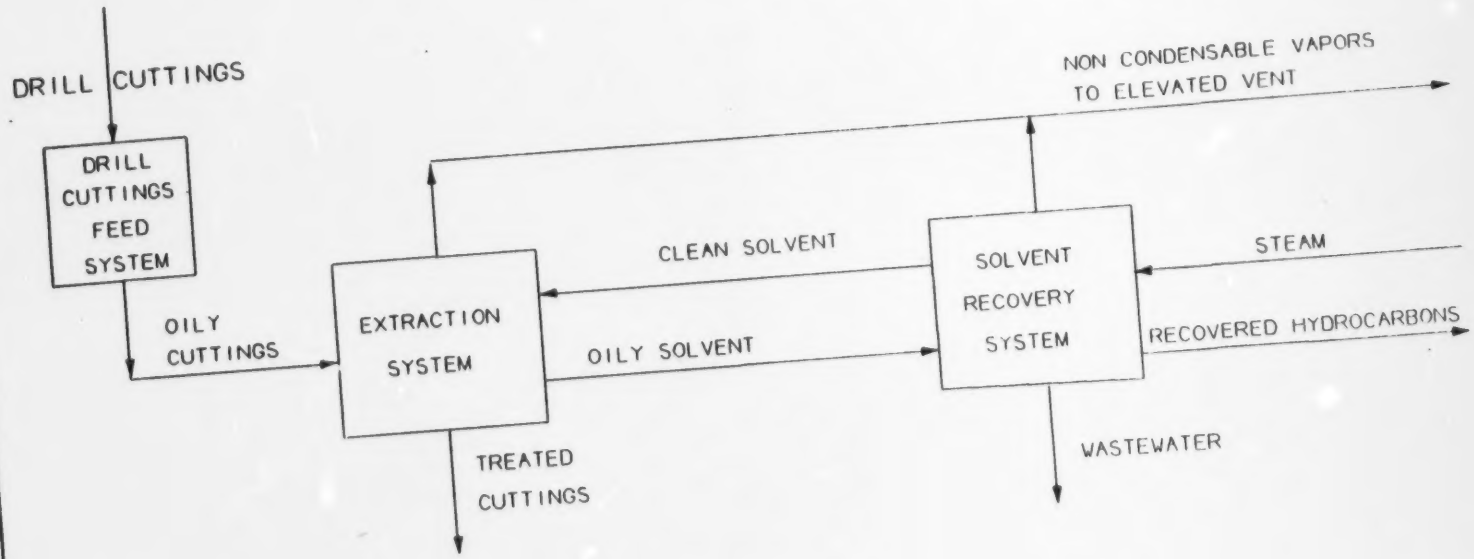

FIGURE 5

with a hydrocarbon content up to 20 weight percent to a level of less than 1 weight percent.

The system requires the following utilities: energy source of low temperature heating media, steam for drying treated cuttings and for solvent recovery, electricity, cooling media, instrument air, and solvent. The manufacturer estimates that the energy requirements for a unit capable of processing 11 tons per hour is 5.0 MMBTU/HR heating media and 180 KWHR of electricity. Half of the required heat can usually be provided by low-temperature waste heat available at the drilling facility.

Cost estimates for the operation of this system are not currently available.

System Design and Selection Considerations

When developing, selecting or planning the use of a system to treat drill cuttings for hydrocarbon reduction, the following factors should be given consideration:

- Methods and modes of operation - The method or mode by which the system operates should not interfere with the drilling operation. It should require few if any operating personnel. The system should be compact so that minimal space is required at the drilling site, especially at offshore facilities where space is often very restricted. Ideally, it would be provided on a turnkey basis.

- Hydrocarbon reduction efficiencies - The system should achieve a consistent level of hydrocarbon removal. It appears that the many of the vendors of the newer technologies are striving to achieve residual hydrocarbon levels of less than 1 weight percent.

- Waste and By-Product

  - Treated cuttings should have a residual hydrocarbon content acceptable for disposal, whether to surface waters or by land disposal.

  - Wastewater discharging from the process would ideally be of a quality not requiring further treatment before disposal.

  - Hydrocarbons discharging the process should be of reusable quality or else be capable of upgrading for recycle or reuse.

- In the case of the solvent extraction process, the solvent loss to the atmosphere should be minimal. Substitutes for chlorofluorocarbons (CFC's) used in these technologies should be sought.

- Materials Handling - The handling of the cuttings in and out of the process units should be kept simple and should be automated. The cuttings should be conveyed directly from the drilling system using, for example, a mechanical or hydraulic system. Interim storage should be supplied to buffer high cuttings generation rates during periods of drilling when peak volumes of cuttings are produced.

- Energy requirements should be kept to a minimum. Emphasis should be given to using waste energy sources available at the drill site.

- The system should be relatively maintenance free. Any required maintenance should be such that it can be performed in short order during periods when drilling is not in progress.

- Safety is an important consideration. The system should be designed with safety in mind and should be free of ignitable and explosive materials. Solvents should be used only in closed systems. The use of hazardous chemicals or materials should be avoided. System design will involve consideration of numerous safety requirements when the equipment is to be operated at drilling sites.

Summary

The manufacturers of most of the drill cuttings treatment processes discussed in this paper indicate that their systems will treat cuttings containing a nominal 20 weight percent of residual hydrocarbon a level of 1 weight percent, or less. All of the manufacturers contacted during the preparation of this paper indicated that the treated cuttings from their process will be acceptable for discharge to surface waters or for land disposal. However, most of the processes discussed are not presently in full-scale operation at any drilling sites or treatment or disposal sites.

These newer technologies can be assembled and operated at active drill sites, whether on land or at offshore drilling facilities. Moreover, these technologies may hold promise for their use in site remediation work to treat a variety of oily wastes at waste

storage, treatment, or disposal facilities.

When selecting a system to process drill cuttings, a number of logistical and design factors should be considered. The capacity of a system, including feed buffering capacity, should be sufficient that during peak drilling times the system can handle any cuttings that must be processed and there should be sufficient power so that the system can be continuously operated. Provisions should be made to enable an operator to operate and maintain the cuttings treatment system on an offshore rig. Since offshore rigs have limited deck space, size and weight should also be taken into account when selecting a cuttings treatment system. Safety aspects should be carefully considered, as should normal operation and maintenance activities. Last but not least, the treatment system should have the demonstrated ability to consistently achieve the required environmental control levels, including requirements for treated waste as well as by-product wastes such as air emissions, wastewater, and waste hydrocarbons.

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PATHWAY EXPOSURE ANALYSIS AND THE IDENTIFICATION OF WASTE DISPOSAL OPTIONS FOR PETROLEUM PRODUCTION WASTES CONTAINING NATURALLY OCCURRING RADIOACTIVE MATERIALS

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ABSTRACT

It has long been recognized that the occurrence of petroleum and natural gas deposits have been associated with the presence of members of the 238 Uranium decay chain, principally 226 radium, 222 radon and daughters. Some of these radioisotopes accompany the produced fluids into the production tubing and surface processing equipment where they are precipitated or deposited as barium, calcium , strontium compounds of sulfate or carbonate that form a very hard and insoluble cement-like coating. These compounds are also brought to the surface with the production sand that is entrained in the produced fluids.

While these materials do not represent a serious external exposure hazard to employees, they are sufficiently active, ranging from a few picocuries per gram to several nanocuries per gram, to require careful handling and disposal. This paper presents the steps followed by one company to identify potential disposal options, and outlines the exposure pathway analysis used to quantify the potential exposure and risk. Conclusions are made with respect to the environmental acceptability of each management option studied.

INTRODUCTION

The identification of disposal options and the establishment of their overall suitability for use is a complicated process. It begins with a thorough understanding of the operation or process generating the waste material. This understanding leads to the definition of scenarios for disposal and the identification of the pathways of exposure to be studied. The completed analysis results in either an estimate of risk or an estimate of the effective dose commitment for the disposal option. The calculated risks or the calculated effective doses are compared with what

is thought to be acceptable, and the basis for a risk management decision is constructed.

Other social, economic, and political factors also impact on any risk management decision concerning radioactive materials. These concerns, while recognized as being often more important than scientific analysis, will not be discussed.

It is the purpose of this paper to describe the exposure pathway analyses used to evaluate options considered for the disposal of petroleum production wastes that are contaminated with naturally occurring radioactive materials (NORM). These NORM contaminants are members of the 238 U and the 232 Th decay chains.

The objectives of this paper are to identify those waste management options for naturally occurring radioactive materials (NORM) that potentially offer environmentally acceptable alternatives for site remediation or disposal; perform pathway exposure analysis to support the finding of overall environmental acceptability and to determine which of the dose performance criteria usually cited offer the highest degree of safety to the general public.

This paper will discuss the origin of NORM in petroleum operations, why the deposition of NORM presents a waste disposal problem for production operations, the type of sites, equipment and location where NORM deposits are found, what are considered the viable disposal options, and the pathways studied. Results of analyses are presented and conclusions made.

THE NATURE OF NORM

The production of crude petroleum is a curious process. Large quantities of water are brought to the surface for processing, the products are extracted, and the water discarded. The products are crude oil and natural gas. The water is called produced water and is usually pumped back into the producing formation or into a zone below the USDW (Drinking water aquifer).

Whether or not a given production well brings NORM to the surface is a matter of geology and formation chemistry. The accumulation of NORM in petroleum bearing strata is probably the result of marine deposition and evaporation. The petroleum is generally assumed to have migrated to a position of minimum hydraulic potential in the reservoir rock, which may or may not be derived from the same source deposits as the petroleum. In general, the uranium is resident in the crude oil and in pellets of solid hydrocarbon, the radon distributes itself in the oil, gas and water in that order of preference, and the radiums are found in the produced water and the solid crusts or scales. In general the decays series are found to be in extreme disequilibrium (NCRP,1975).

The NORM exists on the surface in at least two forms. The first is a heavy, dense, cement-like mixture of barium, strontium and radium

sulfates. This material is precipitated in the production tubing, the well tree and the flow lines. It also tends to settle out in low parts of the line and in the gas-liquid and the oil-water separators. Some of this hard, scale-like material is also trapped in the waste water tanks, pond and sump bottoms and in filters and in the well bore of the well that returns the produced water to the producing formation. Some water flood and steam flood operations such as those in the North Sea have been noted to have enhanced scale production (Smith, 1985). These scales can range from mostly barium to mostly radium though the mostly radium variety are thankfully very rare. Chevron's analyses of scale average approximately 5484 plus or minus 9727 pCi/gm with a range of less than 50 to greater than 30,000 pCi/gm.

The second kind of NORM-contaminated material is thought to be carbonate/silicate material and is usually referred to as formation sand. These materials can settle out in any place in the system when there is a decrease in flow rate, change of direction and is usually found in thick loosely consolidated deposits in the bottoms of tanks, separators, heater treaters and in the bottoms of ponds and sumps. Chevron's analyses suggest that this type of material averages approximately 115 plus or minus 56 pCi/gm total radiums, range 0 to 250 pCi/gm.

Both of these types of materials can be found in the oily, watery deposits found in tank bottoms usually referred to as bottom sediment and water (B.S. and W.), and in filters and other water treatment equipment used to clean up the produced water prior to discharge.

Contamination of the soil in the immediate area of production wells and the clean outs on tanks and equipment has also been noted. These appear to average approximately 310 plus or minus 685 pCi/gm, range 0 to 2,000 pCi/gm total radiums.

POTENTIAL NORM LOCATIONS

It is extremely difficult to describe a generic production site and site layouts depend upon terrain, land use patterns, and population densities. It can be stated, however, that oil wells and crude oil collection stations or tank batteries are removed from people. A typical well site is at least 100 feet by 100 feet while a typical collection station is about 200 feet by 300 feet.

Oil wells are usually spaced one to a quarter section (160 acres) for never fields and somewhat closer for older fields. In some locations where the surface land access is restricted for agriculture etc., one well site may contain several pumping units. The procedure for closing a well site and returning it to the lease holder for unrestricted use is first to plug and abandon the well and then to remove the surface structures and piping, fill in the well cellar, and return the site to grade using a grader or by hand work. A well is plugged and abandoned by squeezing and cementing shut the perforations in the producing zone and and setting a ten foot concrete plug above and below each USDW. The

casing is cut off below plow depth, usually four feet, and a ten foot concrete plug set at the top of the casing. The final step is to weld a cap on the casing and fill in the excavation around the well.

A typical collection station or tank battery usually contains one separator, one heater treater, two to three oil tanks and at least one waste water tank. Pumps for the movement of oil and the disposal of water as well as gas compressors for the movement of the natural gas may also be included. The procedure for closing a tank battery is similar to that for closing a well site. All surface structures and piping are removed, the berms surrounding the tanks are leveled to grade and the site graded to match the local terrain. Sometimes upon closure material from the tank bottoms are buried on the site.

All oil field operations are supported by equipment yards where new material is stored and old material placed before being renovated or sent to scrap. These facilities are usually several hundred yards in width and length and are usually located in or near the small town or camp that supports the field. These facilities are closed by removing structures and fences and grading to blend in with the natural terrain.

Pits containing drilling muds and scrapings are usually left in place and present no environmental hazard. Production pits containing oily materials require a different method. Closure of these pits requires devatering and the removal of the oily sludges from their bottoms. This material is land spread or buried, diluted with clean soil at the site with owners permission, or taken to a licensed oil field disposal site for burial. The pit is then filled and capped with four feet of clean soil and graded to blend with the surrounding terrain.

POSSIBLE DISPOSAL OPTIONS

Previous papers presented by the senior author at the the HPS meetings and an API study (API,1989) have demonstrated that the exposure of employees to external radiation is of little concern except for an extremely limited number of cases. The real problem seems to be associated with the disposal of tank bottoms and other waste materials. Most of this material is just barely radioactive. Philosophically, disposal by dilution at the site of NORM generation seems the most desirable option. The collection and accumulation of large quantities of radium in a single location is more distasteful since it tends to create an external radiation hazard and produce a potentially copious source of radon. Collection of material in containers at a central location can also lead to problems with contamination due to drum filling and handling and the eventual deterioration of the drums and repackaging. Disposal at the site of generation also has the advantage that it will have little impact on existing industry practice to dispose of most non-radioactive oil field waste at the site of generation.

The disposal options suggested here for scales, formation sands and sludges emphasize the reduction of the accumulation of radium, limit the

external gamma ray hazard and minimize the production of point sources radon. These options include are shown below.

1. Surface spreading with and without dilution with clean soil at depths of 1, 3, 10, and 20 centimeters.

2. One-, two- and three-foot layers of buried materials covered with three feet of clean and compacted fill (sludge pit).

3. Burial of four feet of material covered with four feet of clean and compacted fill (production pit).

4. Burial of thin layers of material; 3, 6, and 9 centimeters; with 7 feet (213 centimeters), 10 feet (305 centimeters) and 15 feet (457 centimeters) of cover.

5. Placement in a plugged and abandoned (P and A) well.

EXPOSURE PATHWAY LIMITS

The analyses reported in this paper were performed using four criteria that potentially could be applied to the management of NORM. These are summarized in the first table.

It is also important to ensure that ground water levels of total radium do not exceed that specified by the National Primary Drinking Water Regulations (NPDWR), 5 pCi/l 226 Ra plus 228 Ra.

The exposure limit for the intruder is 100 mRem per year effective dose for all pathways including radon.

SURFACE SPREADING WITHOUT MIXING

NORM materials can be spread without mixing or dilution using equipment or by hand. The material is placed upon the ground and spread in thin layers. The limit of spreading using hand methods is about one half inch (approximately one centimeter). A good equipment operator can spread material to the closest one tenth of a foot (Approximately 3 centimeters). Spreading without mixing can also be used on lease roads within production fields.

SPREADING WITH MIXING

Spreading with mixing or dilution involves the uses of a dozer, road grader or a deep disk plow. The material is placed on the location and spread by hand and then mixed with clean soil using equipment. Road equipment can provide mixing to depths of approximately six inches (15 centimeters) and a deep disk plow to eight inches (20 centimeters).

SHALLOW BURIAL

The shallow burial method of disposal utilizes an existing pit that is being closed or a pit dug usually for that purpose. Such pits are approximately 10,000 square feet but some can be larger. The method here is to open the pit, place the Norm material in lifts mixed with clean soil or other NORM-free wastes of one foot or 31 centimeters and cover the material with a foot or more of clean soil.

DEEP BURIAL

Deep burial is similar to shallow burial except that the top of the buried material is at least three feet below the level of a typical residential cellar or at approximately eight or nine feet from grade.

PLUGGED AND ABANDONED WELLS

The plugged and abandoned well offers unique disposal opportunities for the disposal of NORM below USDW. For this disposal option, the NORM is made into slurry and pumped into the well. The USDW are protected as described above and the well is capped and sealed as before.

EXPOSURE PATHWAYS CONSIDERED

External radiation exposure pathways for residents and intruders were evaluated by integrating the radiation flux above a finite flat plane. Exposure rates were calculated for exposure outside of the houses, a house with a cellar, a house built on a concrete slab and a house with a crawl space. The occupied levels in the house with a cellar and the house with a crawl space were assumed to be one foot or thirty centimeters above grade. The occupied spaces of the house on a slab was estimated to be ten centimeters above grade and the concrete slab was assumed to be four inches thick. In all cases, it was assumed that the exposure takes place at the geometric center of the site. Sites and houses were assumed to be circular to reduce the time of computation. Exposure times were estimated to be one year less two weeks vacation (or 8424 hours) with 25 percent of that time spent outside the home for the resident. The exposure time for intruders was estimated to be six hundred and forty hours or approximately 80 working days.

The generation of radon and resulting radon exposures were analyzed in part using the methods presented by Rogers (NUREG,1984). Radon emanation rates were calculated to determine the surface releases into the atmosphere and into the substructure of the house with a crawl space. No reduction in radon emanation was claimed for the slab of the house built on a slab. Radon concentrations within the crawl space assumed a 53 cubic meter volume and three air changes per hour. Radon breathing zone concentrations for the house with a crawl space were assumed to be one half of those noted in the crawl space. Breathing zone concentrations for the house on a slab assumed a 352 cubic meter volume and two air changes per hour. Radon rates were calculated separately for the house with a

cellar by using the area of the band intercepted by the excavation as the area source. The breathing zone concentrations for radon in the cellar were calculated assuming diffusion into a 352 cubic meter space with one air change an hour. Breathing zone concentrations in occupied portions of the house were be assumed to be one half of those in the cellar. Exposure times were assumed to be the same as in the external exposure pathway.

The airborne dust exposure pathway was analyzed assuming that the dust concentrations was 100 micrograms per cubic meter for the residents and 200 micrograms per cubic meter for the intruder. Ventilation rates used are those for the ICRP (International Commission on Radiological Protection) reference man.

The ingestion of soil materials was assumed to be one hundred milligrams per day for residents and two hundred milligrams per day for the intruder.

The specific activity of the soil was assumed to be the same as the final surface specific activity achieved by the disposal method.

The water pathway assumed that the well was located at the geometric center of the disposal site, that the material was in contact with the drinking water aquifer of approximately 10 meters in thickness and that all the water used on the site came from that well. (In actual practice the drinking water sources would be protected from NORM contact.) The method of calculation followed that presented by Till and Meyer, (NUREG, 1983), and assumed times short with respect to the physical half life of 226 Ra. The calculation assumed an effective soil porosity of .35, a total porosity of .4 and a distribution coefficient of 2500. The magnitude of the release was assumed to be the quantity of Radium put into solution by one year's rainfall and watering.

The calculations for the food ingestion pathway followed the method presented by Till (NUREG, 1983a) and the National Commission on Radiation Protection and Measurement (NCRP,1984) with modifications to adjust the calculations for spread material, wet and dry deposition not being a factor. The depth of the root zone was assumed to be no greater than twenty centimeters. The concentration ratio used in the calculations for vegetable crops and forage was .001 pCi/kg plant per pCi/kg soil and a crop yield of one kilogram per square meter was assumed. The transfer factor for meat and milk were also assume to be .001 in appropriate units. The animals used for meat and milk were assumed to drink water from the well on site and consume forage grown on the site at the rates specified by the NCRP.

It was also assumed that 50 percent of the vegetables, meat and milk products consumed by residents on the site were raised at the site. Annual consumption figures for the exposed individuals were assumed to be two hundred kilograms of vegetable foods, one hundred kilograms of meat

and meat products, and three hundred liters of milk and milk products (NCRP,1989).

RESULTS

The completed analysis for each disposal/remediation option offers much reason for optimism with respect to the environmental acceptability of on-site NORM management. Final maximum levels in the NORM layer after application of the management option are presented in tables 2 through 7 for each case covered. Data for the P and A well case is not presented because there was no specific activity for which this management option produced a significant or measurable surface dose.

In summary, land spreading appeared to be an environmentally acceptable option for rates of application less than 8,300 pCi/ft2. This application rate is calculated by converting the final specific activity, SA, at a depth d, to specific activity per square centimeter (SA*d= SA/cm2) and multiplying that number by 929 square centimeters per square foot.

Similarly, shallow burial at three feet appears to be acceptable when the application rates are less than 9,200 pCi/ft2 for a one-foot layer, 17,500 pCi/ft2 for a two foot layer and 25,000 pCi/ft2 for a three-foot layer.

Burial of four foot of waste with four feet of cover as in the closure of a production pit appears acceptable when application rates are less than 45,000 pCi/ft2.

Deep burial does not appear to be as acceptable as shallow burial at depths less than 15 feet (457 centimeters). The maximum application rates at seven feet (213 centimeters) of cover are 1,100, 2,000, and 2,400 pCi/ft2 for 3, 6, and 9 centimeter layers, respectively. The maximum rates of application with 10 feet (305 centimeter) of cover are 2,400, 4,700, and 7,000 pCi/ft2 for the same thicknesses of application while those for 15 feet are 11,000, 22,000 and 33,000 pCi/ft2.

The plug and abandon option for wells has been reviewed and it is hard to envision any population dose even at the highest of specific activity found once the plug and cap are in place.

Review of the data in tables 2 through 7 indicates that the dose criteria that most severely limits the acceptable final specific activity and the maximum acceptable application rate is the 100 mRem from all routes case. The dose plus radon case appears to apply only for cases where Radon emission is maximized.

CONCLUSIONS

These analyses support the following conclusions with respect to the on site management of NORM.

1. All the management options studied appear to be environmentally acceptable.

2. The use of the P and A well appears to be the most desirable disposal option.

3. Surface spreading appears to be a viable option for site remediation.

4. Shallow burial as in the remediation of production pits appears viable in humid environments but of limited value in arid environments.

5. Deep burial is not a desirable option where construction practice includes cellars.

6. The use of the 100 mRem total dose criteria from all routes including Radon appears to offer the highest assurance of safety.

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TABLE 1: DOSE ENDPOINTS USED FOR STUDY

25 mRem per year, internal plus external exposure excluding Radon.

Time Weighed Average Annual Exposure to Radon less than 2 pCi/l.

Linear Combination of the Above:
TOTAL DOSE/25 + RADON CONC/2 ↔1.

100 mRem per year including Radon.

TABLE 2: IMPACT OF MANAGEMENT OPTIONS ON FINAL PERMISSIBLE SPECIFIC ACTIVITY

DEPTH (CM)	SLUDGE HUMID (pCi/gm)	SLUDGE ARID (pCi/gm)	SCALE HUMID (pCi/gm)	SCALE ARID (pCi/gm)
1	8.1	8.7	9.5	9.6
3	3.3	3.3	4.9	4.9
10	1.0	1.0	2.9	3.0
20	0.5	0.5	2.2	2.2

LIMITED BY: DOSE & RADON FOR 1 cm SLUDGE AND FOR 1, 3, and 10 cm SCALE
100 mREM FOR ALL OTHER CONDITIONS

SURFACE SPREADING OF SCALE AND SLUDGE

TABLE 3: IMPACT OF MANAGEMENT OPTIONS ON FINAL PERMISSIBLE SPECIFIC ACTIVITY

DEPTH OF MATERIAL (FEET)	SLUDGE HUMID (pCi/gm)	SLUDGE ARID (pCi/gm)	SCALE HUMID (pCi/gm)	SCALE ARID (pCi/gm)
1	12.6	0.34	48.3	1.50
2	5.9	0.31	25.4	1.35
3	4.0	0.30	17.2	1.31
LIMITED BY:	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE

BURIAL OF SCALE AND SLUDGE, 3 FEET OF COVER

TABLE 4: IMPACT OF MANAGEMENT OPTIONS ON FINAL PERMISSIBLE SPECIFIC ACTIVITY

DEPTH OF MATERIAL (FEET)	SLUDGE HUMID (pCi/gm)	SLUDGE ARID (pCi/gm)	SCALE HUMID (pCi/gm)	SCALE ARID (pCi/gm)
4	3.03	0.40	13.1	1.76
LIMITED BY:	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE

BURIAL OF SCALE AND SLUDGE, 4 FEET OF COVER

TABLE 5: IMPACT OF MANAGEMENT OPTIONS ON FINAL PERMISSIBLE SPECIFIC ACTIVITY

DEPTH OF MATERIAL (CM)	SLUDGE HUMID (pCi/gm)	SLUDGE ARID (pCi/gm)	SCALE HUMID (pCi/gm)	SCALE ARID (pCi/gm)
3	4.5	0.39	19.3	1.7
6	3.9	0.36	16.9	1.6
9	3.7	0.34	16.2	1.5
LIMITED BY:	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE

DEEP BURIAL OF SCALE AND SLUDGE, 213 CM COVER

TABLE 6: IMPACT OF MANAGEMENT OPTIONS ON FINAL PERMISSIBLE SPECIFIC ACTIVITY

DEPTH OF MATERIAL (CM)	SLUDGE HUMID (pCi/gm)	SLUDGE ARID (pCi/gm)	SCALE HUMID (pCi/gm)	SCALE ARID (pCi/gm)
3	136	0.86	186	3.8
6	135	0.84	186	3.7
9	135	0.84	185	3.7
LIMITED BY:	100 mREM TOTAL DOSE	100 mREM TOTAL DOSE	DOSE & RADON	100 mREM TOTAL DOSE

DEEP BURIAL OF SCALE AND SLUDGE, 305 CM COVER

TABLE 7: IMPACT OF MANAGEMENT OPTIONS ON FINAL PERMISSIBLE SPECIFIC ACTIVITY

DEPTH OF MATERIAL (CM)	SLUDGE HUMID (pCi/gm)	SLUDGE ARID (pCi/gm)	SCALE HUMID (pCi/gm)	SCALE ARID (pCi/gm)
3	188	3.9	184	17.1
6	186	3.9	183	17.1
9	184	3.9	183	17.1
LIMITED BY:	DOSE & RADON	100 mREM TOTAL DOSE	DOSE & RADON	100 mREM TOTAL DOSE

DEEP BURIAL OF SCALE AND SLUDGE, 457 CM COVER

PILOT BIOREMEDIATION OF PETROLEUM CONTAMINATED SOIL

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ABSTRACT

Bioremediation of various petroleum hydrocarbons occurred during a four month period at the Carlow Road, Port Stanley site. Intensive biological and physical operations resulted in a decrease of all contaminants which were monitored including BTEX compounds, Oil and Grease, and Polycyclic Aromatic Hydrocarbon compounds. Percentage reduction of 2 and 3 ring, 4 and 5 ring PAH's decrease as molecular weight increased.

I. INTRODUCTION

The Carlow Road site is located within the Village of Port Stanley, Ontario, Canada and is a former oil gasification site utilized from the 1920's to the 1950's. A by-product of the oil gasification process was a tar-like material (oil tar) which was stored in two open pits on site. In 1970, these two pits were filled in with material dredged from Port Stanley Harbour and subsequently resulted in the spreading of the oil tar over site surface soils.

Approval from the Ministry of the Environment (MOE) for a waste processing site at the Carlow Road property was based on the pilot-scale, on-site remediation of approximately 4,800 cubic meters of oil tar contaminated soil.

The purpose of the pilot project was to demonstrate that:

1) during bioremediation, all emissions from the site could be controlled to acceptable levels;

2) the PAH concentrations could be reduced to acceptable levels (through visual inspection, analytical testing and leachate extraction testing);

3) bioremediation could be undertaken in a reasonable time frame; and

4) bioremediation could be undertaken in a cost effective manner.

A three party consortium was assembled to address the project. Conestoga Rovers and Associates (CRA - Waterloo, Ont.) was retained by the client to provide engineering services and to provide a technical review and performance assessment of the biodegradation technique. Sevenson Environmental Ltd.

(Burlington, Ont.) provided all construction, health and safety, and associated services. Waste Stream Technology, Inc. (Buffalo, N.Y.) provided bioremediation technology and expertise.

The pilot scale bioremediation construction commenced in August 1988 and consisted of securing the site, preparing the bioremediation area to accept contaminated material, excavating the contaminated soil and biological treatment and tilling of the oil tar contaminated soil.

The contaminants identified at this site include Benzene, Toluene, Ethylbenzene, Xylene (BTEX), Oil and Grease, and Polycyclic Aromatic Hydrocarbons (PAH's). A complete analysis of a "pure" oil tar sample was performed by Ecology and Environment, Inc.

Review of Literature - Biodegradation of Polycyclic Aromatic Hydrocarbons

A large volume of literature exists pertaining to the environmental fate and biodegradation of PAH's, with Petroleum Microbiology (1984, Macmillan Publishing Co., New York, NY) representing one of the most recent and comprehensive reviews of information available on work in this area. The author reviews the biodegradation of aromatic hydrocarbons, emphasizing the enzymatic mechanism used by microorganisms, and indicates the similarities and differences between microbial and mammalian metabolism of aromatic hydrocarbons, shared by most microbes that have been studied.

Bacterial degradative pathways for aromatic hydrocarbons ranging from benzene to benzo(a)pyrene are presented in this reference. Extensive lists of bacterial species having demonstrated the capability to degrade aromatic hydrocarbon to various degrees are also provided, and the information available shows that various genera and species of bacteria are capable of complete mineralization of PAH's. In all cases, biodegradation rates are shown to be proportional to solubility, with growth on an alternate substrate required for degradation of the higher, more hydrophobic ring structures.

II. METHODOLOGY

Mobilization

The 500' by 200' biotreatment facility was constructed using three 15 cm lifts of clay compacted after each lift resulting in a permeability of 10 to the minus seven cm/sec. Clay faced berms surrounded the biotreatment pad completing the containment facility. A total of 7,536 cubic meters of clay was used in the construction of the clay liner. A clay-dike was erected to provide a water storage area for site dewatering (100' X 200').

The on site presence of Waste Stream personnel began on August 22, 1989. At this time the WST trailer containing four bioreactors was positioned parallel to the treatment area.

Necessary water and electrical supplies were connected and application of odour suppressant began as soil was added to the containment/treatment facility on August 26. Initial application of bacteria was made on August 30.

Grid and Zone Layout

The clay bioremediation area (400' X 200') was delineated using wooden stakes placed at ten foot intervals along the berm. This resulted in 800 grids. Twenty zones were established by grouping 40 grids in each, to facilitate soil sampling and to represent the area. The zones were grouped into four quadrants for convenience of bacterial application.

Health and Safety

A health and safety plan designed to provide a safe working environment for on site personnel and to prevent the migration of potentially contaminated soil from the excavation was implemented. Prior to hazardous excavation activities, "clean" areas and "work" areas were designated. Within the confines of the "work" areas, a full health and safety program was in effect.

Air monitoring

The air monitoring program was instituted to ascertain the air quality at the site during excavation and treatment of contaminated soils. The program consisted of real time air monitoring, and air quality sampling and analysis. For evaluation purposes, the Ministry of Labour (MOL) Air Quality Threshold Limits were used. Five air monitoring stations were established in, around, and downwind of the bioremediation area.

Excavation

Excavation of the oil tar contaminated soil began at the western most portion of a pit closest to the biopad. The material was marbleized in appearance and pockets of "free product" were encountered. Excavation proceeded to the water table (clay layer) at approximately 17'. The material was transferred in lined dump trucks to the biopad.

Sampling Procedure

The sampling regime was relatively intensive as a demonstration effort under the pilot program. There was an initial sampling round after approximately 4,800 cubic meters of soil was placed in the bioremediation facility, prior to any nutrient/bacterial application. There were four subsequent sampling rounds at approximately two week intervals. Sub-samples were collected randomly within each grid zone, by using nodes, and at various depths within the soil column to form composite samples. Round one consisted of 63 composite soil samples and round 4 included 20 soil samples. Round 1A was composed of 11 grab samples, and rounds 2 & 3 contained 39 samples each. Samples were taken using a split spoon sampler. The sampler was thoroughly rinsed, and dried, so that no soil remained on the sampler. The samples were chopped and kneaded to ensure as homogeneous sample as possible. It was then properly stored and preserved, recorded on the chain of custody log, and shipped to the appropriate laboratory.

Nutrient and Bacterial Application

The excavated soil was prepared for bacterial application by the addition of nutrients. A nitrogen source for bacterial growth was applied to supplement the nutritional requirements of the bacteria being used. This was usually applied by dissolution in 400 gallons of water (dictated by soil moisture levels), and sprayed on the soil. Nutrient was applied, as dictated by results from soil tests throughout the treatment period.

The bacterial suspension was prepared including nutrients sufficient for their rapid growth. Bacterial batches were generally started on one day, with populations brought up to application levels overnight, and applied the following day. Bacteria was applied approximately four days a week throughout the treatment period. This application consisted of 1200 gallons of bacterial suspension, which consisted of approximately one third cell mass yield. The suspension was applied through a high pressure distribution system to the soil.

Soil Conditioner

Soil conditioner was applied as an odour suppressant as soil was placed into the containment/treatment facility. The conditioner was also used as a contaminant emulsifier in nutrient applications.

Tilling

The soil was tilled on a daily basis to promote homogenization of

the soil and to increase the amount of oxygen available to the microorganisms. The equipment achieved a total tilling depth of 24". This achieved a more favorable soil matrix by increasing porosity and decreasing aggregate size. The depth of the soil in the facility rose from 25" when it was first leveled in the facility to 33" as a result of the tilling operation. The tilling also achieved a high degree of mixing the nutrient/bacterial applications. These factors combined, resulted in an environment favorable to bacterial growth, maturation, reproduction, and subsequent degradation of the waste.

III. DATA

Soil Nutrient Test Data

Soil testing for macronutrients available in the soil was performed. Data was collected for six macronutrients and pH: nitrate nitrogen, phosphorous, potassium, ammonia nitrogen, calcium, nitrite nitrogen. All of these nutrients are vital to the growth of the bacteria and are thus carefully monitored. Soil sampling began as early as May 27, 1988. Weekly sampling began on August 31, 1988 and the final soil test sample was collected on January 10, 1989.

Summary of Bioremediation Work Performed

Each day on site was recorded in a daily log, along with the work performed on the site. Work categories and the total number of each are: samples collected (245), bacterial colony counts (32), soil tests (53), 27 bacterial applications (35400 gallons), nutrient applications (15), times tilled (28) and other site work performed such as mobilization and excavation.

Analysis of Soil Samples

Analysis of soil samples for BTEX compounds was performed by Novalab, Lachine, Quebec, using EPA Method 8240.

Analysis of soil samples for oil and grease was performed by Waste Streams in-house laboratory using EPA Method 9071.

Analysis of soil samples for PAH's was performed primarily by Flow laboratory, McLean, Virginia, using EPA Method 8310 and by Novalab using Method 8270.

Extraction of selected soil samples was performed by an independent engineering firm using Ontario's Regulation 309.

IV. . RESULTS

Initial Statement of Results

Application of the soil conditioner agent resulted in the immediate suppression of odours emanating from the containment/treatment facility.

A qualitative but significant observation can be made about the progress of the bioremediation of the soil. Visual appearance of the soil in the bioremediation area progressed from black to brown during the treatment period and olfactory detection decreased markedly.

Soil Nutrient and pH Levels

Graphs were produced which represent macronutrient and pH levels over the length of the treatment period. Results indicate that all soil nutrient levels were sufficient and utilizable by the bacteria for rapid and sustained growth.

The pH levels fluctuated between 6.0 and 7.5, the average being 7.0. This is optimum pH for bacterial growth and maturation.

Soil Temperature Profile

Soil temperature (at a depth of 0.62 m) dropped from 19 degrees Celsius to 12 degrees in the period of 35 days. This is important information when interpreting the bacterial growth (and mortality) curve. A direct correlation may be made as the temperature decreases, so does the bacterial population.

Bacterial Colony Growth

Graph 1 illustrates the establishment and subsequent growth of the microbial organisms in the soil matrix. This graph represents successive additions of bacteria throughout the treatment period. Each data point is an average of four soil samples checked for bacterial presence and enumeration. The bacterial population was firmly established by early September and reaching a maximum of 3.39 X 10 to the forth colonies per ml of solution, in soil samples taken on September 23.

This curve is very similar to the classic Monod bacterial population growth curve, rising exponentially, peaking and then decreasing exponentially. This indicates that the entire remediation area exhibits typical bacterial colony growth characteristics. The decline in the level of biological activity, in this case, was clearly due to the decrease in soil and ambient temperature.

Volatile Aromatic Compounds

Twenty - two samples were analyzed for volatile organic compounds. Relatively low levels of these compounds were present at the onset of bioremediation, however, this class of contaminants was greatly reduced by the end of the project.

Oil and Grease Levels

Twenty samples were analyzed for round one and twenty samples for round four. Initial maximum levels exceeded 5,000 ppm. The test method used includes extraction of biological lipids and therefore was not an accurate indicator of degradation.

Total Polycyclic Aromatic Hydrocarbon Levels

Graph 2 represents the Total PAH levels from the initial to the final sampling. The graph illustrates four sampling rounds and a minimum of 20 samples per round. Initial Total PAH levels in the soil samples were measured prior to the beginning of any bioremediation effort. Maximum levels exceeded 3,000 ppm (TPAH). Round four samples indicated an average level of approximately 45 ppm. TPAH compounds.

Two and Three Ring PAH's

Graph 2 also illustrates the biodegradation of two and three ring PAH's. Two ring compounds include Naphthalene, Acenaphthylene, Acenaphthene, and Fluoranthene. Three ring compounds include Phenanthrene, Anthracene, and Fluorene. Maximum levels of these compounds approached two thousand ppm. initially and were reduced by more than 90% during the bioremedation period.

Four Ring PAH's

Four ring compounds include Pyrene, Chrysene, Benzo(a)anthracene, Benzo(b)fluoranthene, and Benzo(k)fluoranthene. Maximum initial levels were one thousand ppm. for round one and decreased by 80% in the soil samples analyzed in round four.

Five Ring PAH's

Five ring compounds include Indeno(1,2,3)pyrene, Benzo(a)pyrene, Dibenzo(a,h)anthracene, and Benzo(g,h,i)perylene. These contaminants were reduced by approximately 65% over the course of the bioremediation project.

Benzo(A)Pyrene Levels

Benzo(a)Pyrene was of particular concern because of its persistent nature and toxicity. Initial maximum levels of B(a)P approached 70 ppm. This compound exhibited a reduction of greater than 60% which coincides with the degradation of other five ring PAH's.

Leachate Results

The results of the analysis of water samples prepared using the leachate extraction procedure in Regulation 309 of the Ontario Environmental Protection Act, indicated that there were no B(a)P contaminants present in the extract. This indicates that any B(a)P, which may have had the potential to leach from the soil, apparently did not.

V. DISCUSSION

Summary of Results

Biodegradation of various petroleum hydrocarbons occurred during a 4 month period at the Carlow Road, Port Stanley site. Intensive biological and physical operations resulted in a decrease of all contaminants which were monitored including BTEX compounds, Oil and Grease, and Total PAH compounds. Percentage reduction of 2 and 3 ring, 4 and 5 ring PAH's decrease as molecular weight and number of rings increases.

Review of Purpose of Bioremediation Pilot Project

This section addresses the four points pertinent to the pilot bioremediation.

1) During bioremediation can all emissions from the site be controlled to acceptable levels?

Excavation of oil tar contaminated soil resulted in localized air quality impact within the immediate work space. Volatile compounds Benzene and Naphthalene were measured above Ontario MOL threshold values. Workers were protected by appropriate respiratory equipment. Bioremediation of the soil did not impact air quality within the work area above the limits. Activities did impact on-site air quality as demonstrated by sampling results for dust, BTEX's, and PAH's which were all below MOL threshold levels.

2) Can the PAH concentrations be reduced to levels as established by the MOE including visual inspection, analytic testing, and leachate extraction testing?

WASTESTREAM TECHNOLOGY

Criteria set forth in the MOE letter of concurrence was met as presented:

	MOE Criteria	Analytic Results
Total PAH in soil	100 ppm	45.4 ppm
B(a)P in soil	10 ppm	3.8 ppm
B(a)P in leachate	(0.1 ppb	ND (0.01)

3) Can bioremediation be undertaken in a reasonable time frame?

Yes, contaminant levels were reduced by an average of 65% during the four month treatment period.

4) Can bioremediation be undertaken in a cost effective manner?

It appears that bioremediation can indeed be done in a cost effective manner. It is a technology which is economically attractive as compared to other options such as landfilling and incineration. Bioremediation offers a permanent solution to an environmental hazard.

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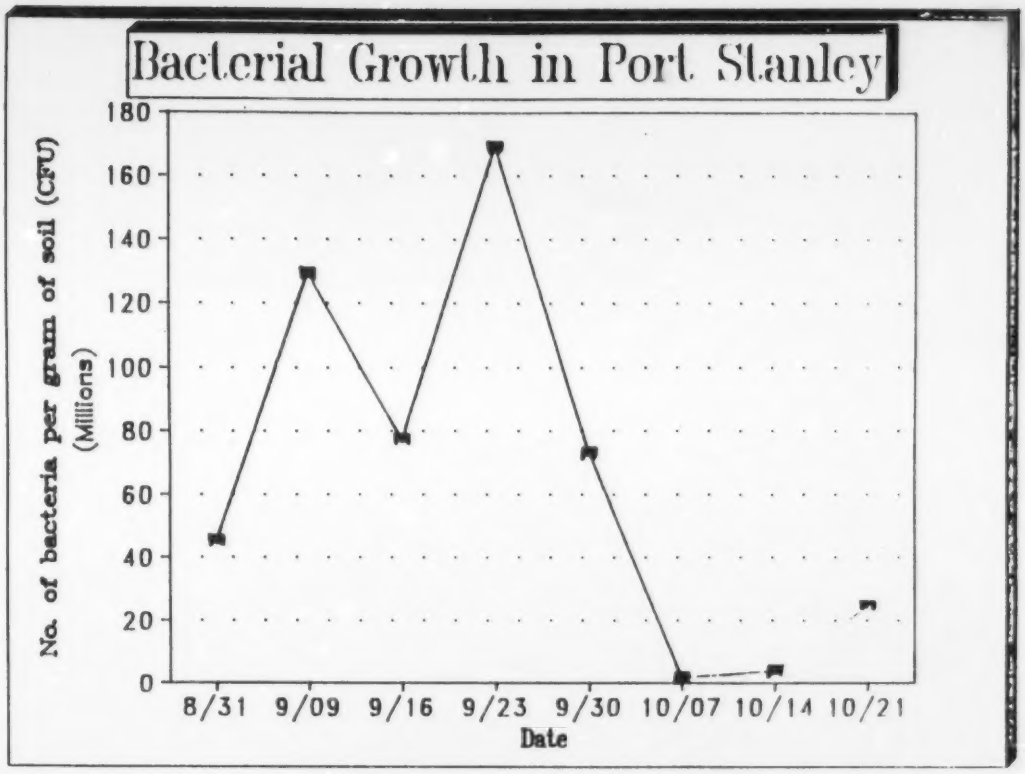
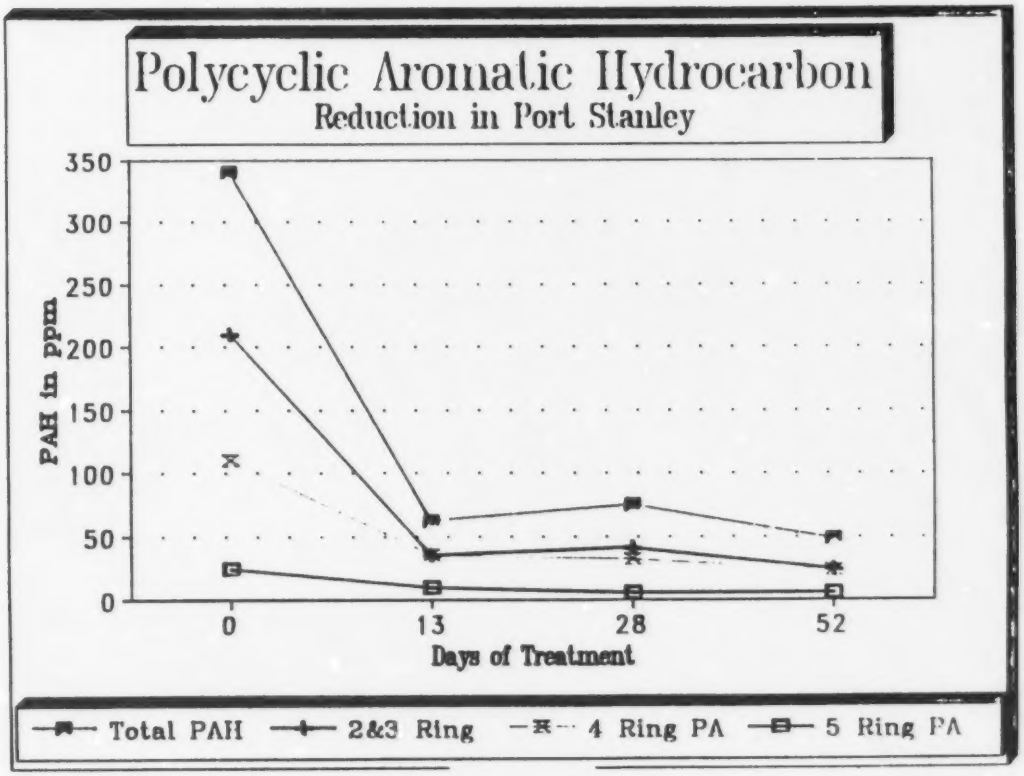
GRAPH 1



GRAPH 2



POLICY AND REGULATORY IMPLICATIONS OF COAL-BED METHANE DEVELOPMENT IN THE SAN JUAN BASIN, NEW MEXICO AND COLORADO

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Abstract

An upsurge in the development and production of coal-bed methane in the San Juan Basin of northwestern New Mexico and southwestern Colorado has coincided with the discovery of extensive natural gas contamination of an alluvial aquifer in the Animas River valley of the basin. Studies conducted by state and federal agencies in the past 18 months indicate that the production of natural gas from deep coal seams is at least partially responsible for the presence of thermogenic gas in private domestic water wells, in alfalfa field seeps, at the surface casings and Bradenheads of gas-producing wells, and in cathodic protection holes in a 25-mile stretch of the river valley. This paper summarizes the scientific data that implicate the production of coal-bed methane in the contamination of fresh waters in the area. Water quality and gas composition data reported by state and federal agencies are reviewed. Methods used to identify the stratigraphic origin of the migrating gases are summarized. The mechanism by which coal-bed methane migrates upward nearly 3,000 feet to ground water is described. The scientific evidence is correlated with local residents' accounts of the onset of "gassy" water in domestic wells in the region. Regulatory actions taken by state and federal agencies to address the gas-migration problem are reviewed. Volumetric and chemical characteristics of water produced from the coal seams of the Upper Cretaceous Fruitland Formation are reported and compared with similar data for conventional sandstone gas reservoirs in the basin.

New policies and regulatory initiatives are needed to prevent further gas migration and to address the unique problems posed by production of natural gas from coal seams. Multijurisdictional planning, cumulative environmental analyses, cementing of existing gas-producing wells, pre-lease environmental audits, and temporary moratoria on new leasing are suggested. A corrective action and compensation fund to remediate contaminated ground water and to compensate property owners for damages is recommended.

Introduction

Development and production of coal-bed methane has increased dramatically in 13 major geologic provinces in the United States in the 1980s.(1) Once considered a "nuisance" by drillers(2) and a lethal hazard for coal miners, coal-bed methane today is sought for its energy potential and because it qualifies for federal tax credits as a nonconventional fuel.(3) Two-thirds of the nation's coal-bed methane resources are located in five Rocky Mountain states. (Table 1) With an estimated 88 trillion cubic feet of coal-gas resources, the San Juan Basin (Fig. 1.) of northwestern New Mexico and southwestern Colorado leads the nation in coal-bed methane reserves. The expiration of the tax credits on December 31, 1990, coupled with the opening of gas markets in California and the Pacific Northwest, has fueled extensive exploration and development programs by several major gas producers in the San Juan Basin in the past decade. Between October 1987 and May 1990, more than 900 coal-bed methane wells were permitted on U.S. Bureau of Land Management (BLM) lands in the New Mexico portion of the basin.(4) State and federal officials estimate that 1,200 wells will be approved by regulatory agencies in New Mexico in 1990, with approximately 700 wells being completed this year alone.(5) Several hundred more coal-bed methane wells have been approved for drilling or are planned on private, state, federal (BLM and U.S. Forest Service), and Southern Ute Indian lands in the Colorado portion of the basin.(6)

TABLE 1

Coal-bed methane reserves of the U.S.
(in trillions cubic feet of natural gas)

San Juan Basin (northwestern N.M.-southwestern Colo.)	88
Piceance Basin (northwestern Colo.)	84
Northern and Central Appalachia	66
Powder River Basin (northeastern Wyo.-southeastern Mont.)	39
Green River Basin (southwestern Wyo.)	31
Western Washington Basin (Wash. state)	24
Illinois Basin (northern Illinois)	21
Black Warrior Basin (western Ala.)	20
Raton Mesa (northeastern N.M.)	18
Arkoma Basin (southeastern Okla.-southwestern Ark.)	4
Wind River Basin (central Wyo.)	2
Uinta Basin (northeastern Utah)	1

Source: Oil and Gas Journal, October 9, 1989, 50.

Natural gas from coal seams of the Fruitland Formation was first tapped on an experimental basis in 1952. Thirty different coal-gas pools were created in the basin before 1980, but large-scale development of the Fruitland gas reserves never materialized in that three-decade period.(7) During that time, coal-bed gas was virtually ignored because of its low heat content, its propensity to cause gas-well blowouts, and the fact that hundreds of thousands of barrels of produced water must be pumped off the coal seams before production of the gas can reach profitable levels. By the mid-1980s, a handful of companies began coal-bed methane development programs in order to take advantage of the tax credits that were authorized by the Crude Oil Windfall Profits Tax Act of 1980.(8) The amount of the credit escalated each year, and by 1987 had reached 78 cents per thousand cubic feet (MCF) of natural gas. Today, in an era of surplus natural gas, coal-bed methane producers receive more income from the tax credit than from the sale of the gas.(9)

Coincidental with the upsurge in coal-bed methane production in the basin in the 1980s was an increase in the number of complaints of water contamination among residents of Cedar Hill, New Mexico, and Bondad, Colorado. (Fig. 1.) Those complaints led officials of the New Mexico Oil Conservation Division (NMOCD) to collect water samples from private wells in the transboundary area. The presence of organic vapors in about 30 percent of the water samples and the identification of Fruitland coal gas in three private wells in Bondad confirmed that deep-formation gas had migrated into the shallow alluvial aquifer of the river valley. These findings have prompted citizens groups in the area to request cumulative environmental assessments of coal-bed methane development prior to further leasing actions by state and federal agencies.(10)

Summary of the Scientific Data

The scientific evidence that links coal-bed methane development to contamination of fresh ground water in the Animas River valley includes:

- Analytical data for more than 250 samples of water from nearly 200 different domestic water wells in the region;
- Chemical and carbon isotopic composition data for 48 gas samples collected from water wells, gas seeps in fields and in the Animas River, the surface casings and Bradenheads of gas-producing wells, and cathodic protection holes adjacent to producing wells; and
- Previous studies on the genesis of natural gas and the techniques for identifying the geologic origin of natural gases.

Interviews with 15 different long-time residents of the communities of Aztec and Cedar Hill, New Mexico, and Bondad, Colorado, were conducted to obtain anecdotal accounts of the presence of gas in the alluvial river valley. Information from those interviews supplements the scientific data.

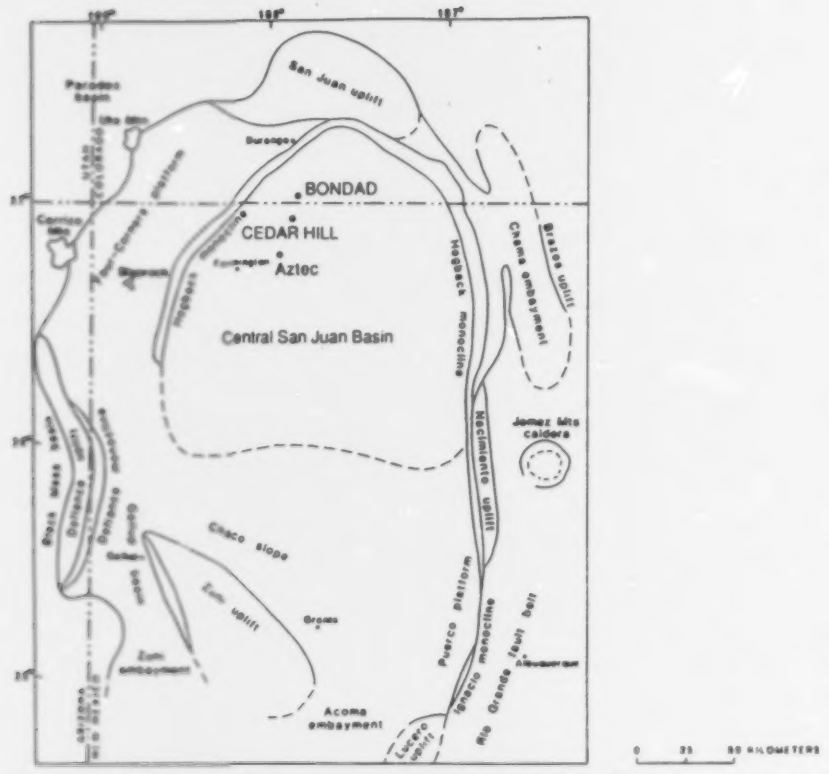

Fig. 1. Map of the San Juan Basin showing major structural elements and population centers. Coal-bed methane production is concentrated in the northern flank of the basin around Ignacio and Bayfield in Colorado, and Cedar Hill and Navajo Lake in New Mexico. Adapted from Rice, et al. (1989).

WATER QUALITY DATA. Analytical data for water samples collected by NMOCD from private water wells in the Bondad-Cedar Hill-Aztec area since early 1985 were gathered from the agency's files and assembled for this paper.(11) Table 2 shows a statistical analysis of the results. About 30 percent of the samples (57 of 187) tested positive for organic vapors. Of those, 47 samples (or 25 percent of the total) exhibited concentrations greater than 10 parts per million (ppm). Twenty-two samples from 17 different wells had concentrations of organic vapors of 1,000 ppm or greater. Four of 32 wells tested for explosivity registered 100 percent of the lower explosive level. As shown in a map of the study area (Fig. 2), most of those wells are located in a 10-mile stretch of the river valley between Bondad and Cedar Hill. Trace to parts-per-billion levels of aromatic volatile organic compounds (VOCs) were detected in 27 of 79 samples; the highest single concentration was 31 ppb of benzene in a well in Cedar Hill.

GAS SAMPLE ANALYSES. Nearly 50 samples of gas were collected by state and federal agencies from a variety of sources and sites in the Cedar Hill and Bondad areas in 1989. NMOCD collected 24 gas samples in the Cedar Hill area from the Bradenheads (annular spaces) on 10 gas-producing wells, from nine cathodic protection holes, at the surface casings of two gas wells, from a tank discharge value, a river seep, and a seep in an alfalfa field. Personnel from the U.S. Geological Survey (USGS) and Colorado Oil and Gas Conservation Commission (COGCC) collected 24 gas samples in the Bondad area from the wellheads at 10 gas-producing wells, from the Bradenheads at five gas wells, from five domestic water wells, from a seep in the Animas River, from a gas pipeline, from a seismic hole, and from an abandoned gas well. Results of chemical and isotopic analyses for the 48 gas samples were reported by USGS petroleum geologist Dudley D. Rice in letters to COGCC and NMOCD.(12),(13)

TABLE 2

Statistical summary of water quality results, Animas River valley, New Mexico and Colorado 1985-1990
(all samples and results from files of N.M. Oil Conservation Division)

Total number of samples collected, both states	254
Total number of water wells sampled, both states	195
Number of wells sampled in New Mexico	173
Number of wells sampled in Colorado	32
Number of wells sampled at least once for organic vapors, both states	187
Number of wells testing positive at least once for organic vapors, both states	57
New Mexico wells testing positive at least once for organic vapors	48
Colorado wells testing positive at least once for organic vapors	9
Number of samples showing organic vapors	70
Mean organic vapor concentration, in parts per million (n=70)	447.9±450.7
Range of organic vapor concentrations, in ppm	1 to 1,450
Number of wells with organic vapor concentration >1,000 ppm	17
Number of wells with organic vapor concentration 10 ppm ≤ x ≤ 999 ppm	30
Number of wells with organic vapor concentration <10 ppm	10
Number of samples screened for aromatic VOCs	79
Number of samples testing positive for aromatic VOCs	27
Range of aromatic VOC concentrations, in ppm	0.2 to 31
Number of wells tested for explosivity, both states	32
Number of wells testing positive for explosivity	10
Number of wells testing >5% lower explosive limit	7
Number of wells testing 100% lower explosive limit	4

For the gas samples collected near Cedar Hill, Fruitland Formation coal-bed methane was identified as the gas in four of the 10 annular spaces, in three of the nine cathodic protection holes, at the surface casing of one gas-producing well, and in one tank discharge. All of the wells identified as being charged by Fruitland gas produced from the deeper Mesaverde and Pictured Cliffs formations. Hydrocarbon chemical compositions of gas seeps from an alfalfa field and from the banks of the Animas River were suggestive of coal-bed methane, but the carbon isotopic compositions of the gases were lighter than those typically associated with Fruitland coal gas. Gases from the Mesaverde and Pictured Cliffs sandstones were found in four cathodic protection holes, in the annular spaces of four wells that produce gas from those deeper formations, and at the surface casing of a Mesaverde well.(14)

For the gas samples collected near Bondad, Fruitland Formation coal gas was identified in three of five domestic wells. (Fig. 2.) A combination of different thermogenic gases which may have been altered by bacteria in the alluvial aquifer was detected in two domestic wells on the same property. Fruitland coal-bed methane was detected at the Bradenhead of one producing Mesaverde well. Deeper formation gas was identified in the annular spaces of the four other producing wells, in the abandoned gas well, and in a seep from the Animas River. The origin of gas in the seismic hole was not identified.(15)

GENESIS OF THE GAS. The geologic origin of natural gases can be determined by analyses of the chemical and carbon isotopic compositions of gas samples. In the past decade, extensive research has been conducted to identify the chemical and isotopic signatures of natural gases in the northern San Juan Basin(16),(17) The methods used can determine with a high degree of confidence the thermal maturity of the gas and its geologic host rock.

Gases from the Fruitland Formation coal beds has been interpreted to be thermogenic, having intermediate to high levels of thermal maturity.(18) They tend to be dry, i.e., the ratio of methane (CH_4) to heavier hydrocarbon gases is usually greater than 0.99. This ratio is called the "methane fraction" and is denoted by the expression C_1/C_{1-5}, which is the concentration of CH_4 divided by the

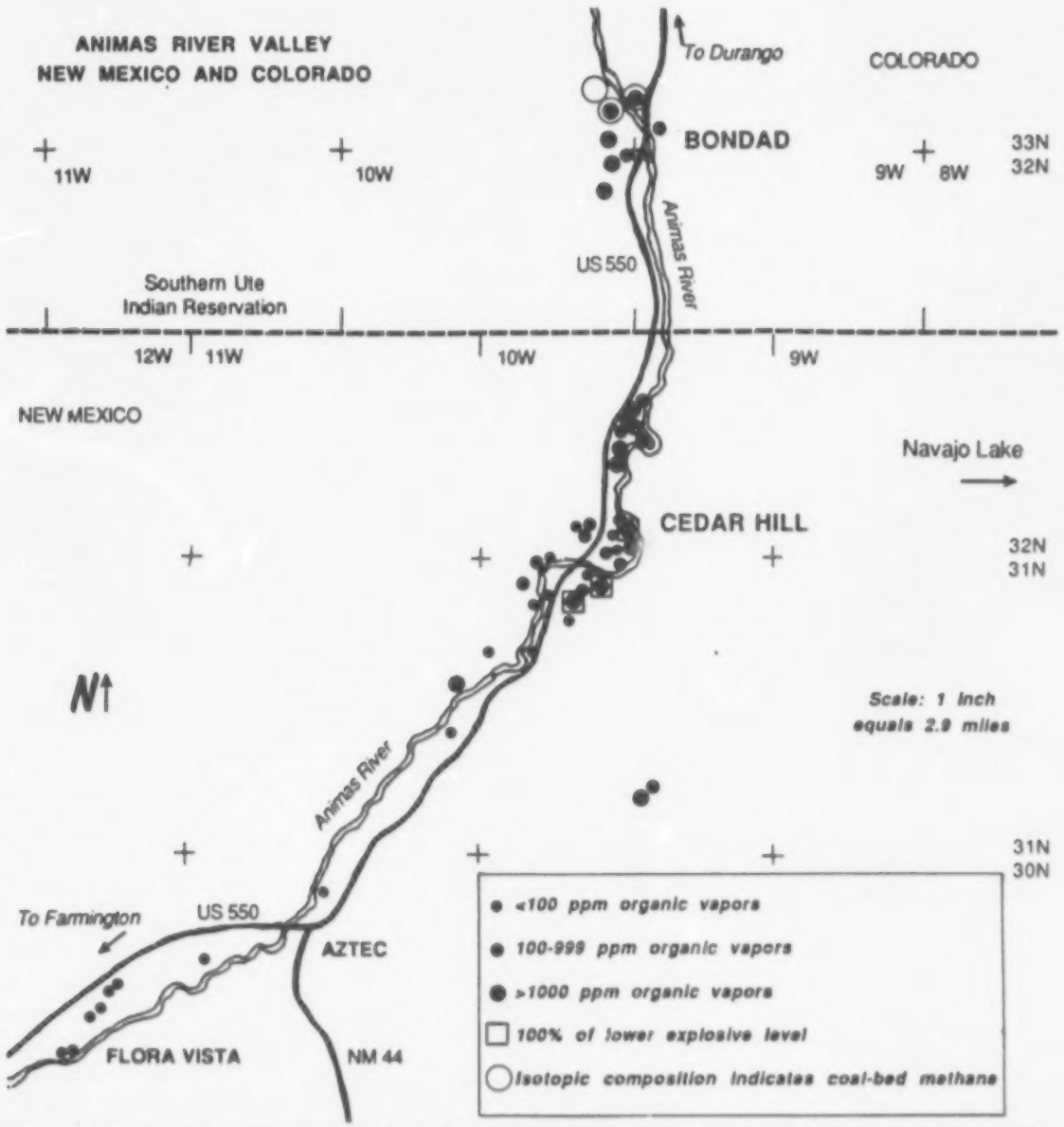

Fig. 2. Map of study area depicting 50 of 57 domestic wells that show indications of contamination by natural gas. Well locations are not exact. Map based on U.S. Geological Survey 7.5-minute quadrangles.

sum of the concentrations of methane, ethane [C_2H_6], propane [C_3H_8], butane [C_4H_{10}], and pentane [C_5H_{12}]. "Wetter" gases have a methane fraction between 0.85 and 0.95 and usually are accompanied by much larger volumes of liquid hydrocarbon condensate. Coal-bed methane, on the other hand, is accompanied by little or no liquid hydrocarbons, especially in the northern part of the basin where the Fruitland Formation coal beds are deeper, have higher thermal maturities, and are under greater pressures. Coal-bed methane from the Fruitland also contains significant amounts of carbon dioxide, often as much as 6 percent.

Carbon isotopic compositions also are used to identify natural gases. Microbial, or biogenic, gases consist primarily of CH_4 that is depleted in the carbon isotope, ^{13}C. Gases in ground water in southern Weld County in north-central Colorado were found to be enriched in the lighter carbon isotope, ^{12}C, meaning they have been generated as a result of biological and microbial decomposition processes at low temperatures and pressures.(19) Thermogenic CH_4 is heavier, i.e., it is enriched in the ^{13}C isotope. Stable carbon isotope ratios are expressed in S-notation per thousand (ppt) deviations, relative to the Peedee belemnite marine carbonate standard.(20) Biogenic gases generally have $\Delta^{13}C_1$ (21) values that are more negative than –55 ppt; thermogenic gases have $\Delta^{13}C_1$ values in the range of –55 ppt to –35 ppt.(22) Gases from the coal seams of the Fruitland Formation have $\Delta^{13}C_1$ values ranging from –40.5 ppt to –43.6 ppt. Figure 3 shows the relationships between gas thermal maturity, methane fraction, and carbon isotopic compositions and graphically depicts the nature of coal-bed methane as a dry, isotopically heavier, and thermally mature gas.

Based on these factors, gases detected in domestic wells, alfalfa fields, river seeps, cathodic protection holes, and annular spaces of gas-producing wells in Bondad and Cedar Hill were interpreted as thermogenic.(23) About half of the gases detected in domestic water wells and in field and river seeps were reported to originate from the Fruitland coal beds.(24) Fruitland gas also was found to be charging the Bradenheads and surface casings of several deeper gas wells.

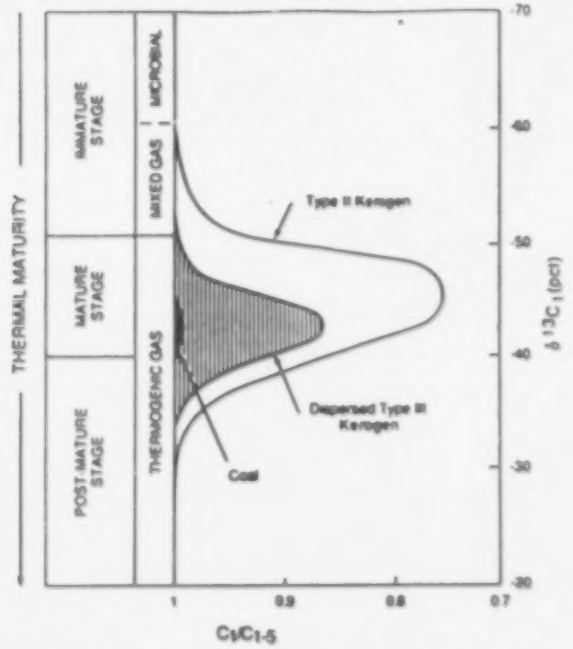

Fig. 3. Graph depicts the relationships between gas thermal maturity, methane fraction, and carbon isotopic compositions. Adapted from Rice et al. (1989), 611.

ANECDOTAL ACCOUNTS OF LOCAL RESIDENTS. The communities of Cedar Hill and Bondad are populated by multigenerational families, many of which have depended on farming and ranching for economic sustenance. Several of the families are headed by "old-timers" who were born in the area or moved there shortly after the turn of the century. Interviews were conducted earlier this year to obtain the residents' accounts of gas migration in the Cedar Hill-Bondad area.(25 The following is a summary of those accounts.

Most of the residents agreed that their observations of gases in the Animas River, in seeps in alfalfa fields (observed during application of irrigation water), and in water in their private wells began relatively recently. None could remember observing gas bubbles in the fields, seeps, or wells before 1980 or 1981. A former county extension agent said he never received complaints of "gassy" water in 22 years of service through the mid-1980s. Four residents in their 70s said the gas in the fields, seeps, and water wells does not have the characteristic rotten eggs odor of the "swamp gas" they often encountered while digging or drilling shallow water wells in the alluvial sediments in the 1930s, 1940s, and 1950s. Several residents recounted an incident in Cedar Hill in which a water well caught fire after a match was tossed into the borehole. And members of one Cedar Hill family said flames roared from a water well after an individual discharged a firearm into the borehole in hopes of opening the perforations at the bottom of the well.

Residents' observations about the newness of gas migration can be correlated with the scientific findings. Rice's studies showed that the Fruitland coal gas generally has been confined to the coal beds and has not migrated to adjacent reservoirs, either above or below the Fruitland. NMOCD scientists have concluded, based on their understanding of the gas migration problem and the regional geology, that natural fractures or other tectonic avenues did not contribute to release of the coal gas prior to depressurization of the coal beds upon their development as gas pools.(26)

Mechanism for Gas Migration

Figure 4 depicts how Fruitland Formation coal-bed methane is believed to be escaping its host rock and migrating into overlying fresh-water zones, such as the surficial alluvial aquifer in the Animas River valley. (The diagram is based on an original drawing prepared by NMOCD's Aztec District staff.) Gas migration as depicted in Fig. 4 occurs as a result of the combination of several factors. The gas is freed from its host rock after the formation pressures are lowered following the installation of gas-producing wells and the pumping off of large volumes of produced water. The gas migrates from the coal bed into overlying strata via the uncemented portions of producing gas wells that penetrate the Fruitland Formation. Once inside the alluvial aquifer, the gas can invade cathodic protection holes or domestic water wells as shown in Fig. 4.(27)

The gas-migration theory was developed by NMOCD geologists based on a combination of the previous water quality studies, pressure testing on gas wells, isotopic analyses of the migrating gas, and their own personal observations and insights. In response to results of the water quality sampling program conducted in and around Cedar Hill and Bondad, NMOCD in the fall of 1989 conducted pressure tests on the surface casings and Bradenheads of producing gas wells in the area. Gas was found to be charging up the casings and annular spaces, indicating that gas either had migrated into the surficial alluvial soils or had escaped the production tubing of producing wells via casing leaks. About the same time, migrating gas was suggested as the cause of two gas-well blowouts and flowing gas and water from two cathodic protection holes in the Cedar Hill and Navajo Lake areas. (Fig. 2.) Having indications that some of the errant gas may have been migrating from the Fruitland Formation coal beds, NMOCD began looking at construction methods used on gas wells that penetrate the Fruitland. It was then that the agency discovered that many deeper gas wells were not cemented through the surficial alluvial aquifer or opposite the Fruitland coal seams. The gas chemical and isotopic composition data subsequently reported by USGS confirmed that Fruitland coal-bed methane was present at the surface casings and Bradenheads of nine different Mesaverde and Pictured Cliffs wells in the Cedar Hill-Bondad area.

Regulatory Responses to the Gas-Migration Problem

To prevent further migration of coal-bed methane, NMOCD in November 1989 ordered gas operators in the Cedar Hill and Navajo Lake areas to apply casing cement to all existing gas wells that penetrate the Fruitland Formation.(28) The agency also also has continued to conduct pressure tests on producing wells in areas where gas wells or cathodic holes are blowing out. BLM's Farmington Resource Area office in February approved a notice to lessees that requires full cementing through fresh-water zones above the gas-producing intervals.(29) By the end of May, NMOCD reported that two major coal-bed methane producers in the Cedar Hill area had plugged 11 wells and were conducting remedial cementing on more than 20 wells. One cement workover was credited with stopping gas seeps in Ditch Canyon, three miles east of Cedar Hill. A cathodic protection hole that was flowing gas and water at the surface also was plugged.(30)

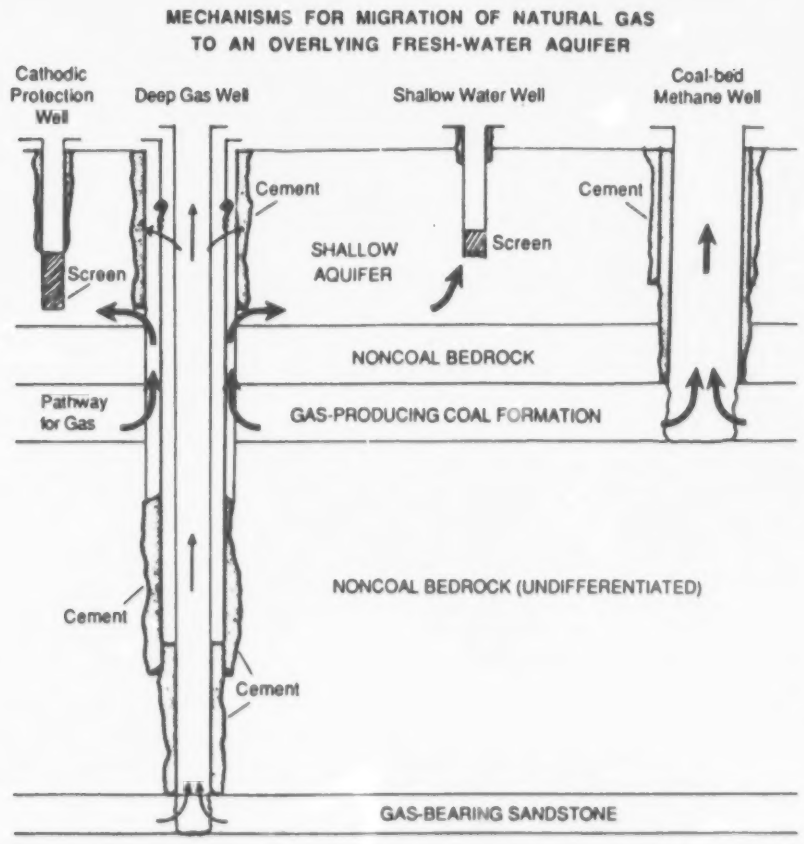

Fig. 4. Diagram shows two mechanisms for the migration of thermogenic gas to a shallow water well and to a cathodic protection hole. The thick arrows indicate how natural gas escapes the coal formation via the uncemented portion of a deep gas well that penetrates the coal seam. The thin arrows show how gas might migrate into the shallow alluvial aquifer from leaks in the casing of the deep gas well. Vertical scale is exaggerated from actual depths.

Characteristics of Coal-Bed Methane Produced Water

Fruitland coal beds were known to produce a distinctive sodium-bicarbonate connate water. Sampling and analyses of coal-bed produced water by NMOCD in mid-1989 showed that the bicarbonate ion made up 50.6 percent to 96.2 percent of the dissolved solids in four samples.(31) Total dissolved solids concentrations in four samples ranged from 10,568 mg/L to 35,728 mg/L. The coal-bed water was consistently low in aromatic VOCs, ranging from nondetectable to less than 10 ppb. Barium was the only trace metal to show elevated concentrations, ranging up to 45.7 mg/L in the four samples. Gross alpha radioactivity and radium-226 + -228 exceeded federal drinking water standards (15 pCi/L and 5 pCi/L, respectively) in all four samples. Maximum gross alpha activity was 120 pCi/L; the maximum concentration of radium-226 + -228 was 34.3 pCi/L.

Produced water volumes reported by operators to NMOCD confirmed that the Fruitland coal beds generate much larger volumes of waste water than do conventional sandstone gas reservoirs. In 1989, 4.5 million barrels of water were produced from 323 Fruitland coal-bed wells, or about 38.4 barrels per well per day (BWD). By comparison, only 652,257 barrels of water (or 0.2 BWD) were

produced from 8,281 gas wells that tap the Basin Dakota and Blanco Mesaverde pools. Those wells comprised 59 percent of all gas wells in the New Mexico portion of the basin and produced 40 percent of the gas in 1989. The 323 Fruitland wells comprised only 2 percent of all gas-producing wells in the New Mexico, but generated 82 percent of waters produced from gas-bearing formations.(32) Through the first three months of 1990, 400 Fruitland coal-bed methane wells had already produced 4 million barrels of water, or about 112.1 BWD. These large volumes of potentially corrosive water are likely to be even greater, given that only 35 percent (125 of 359) of coal-gas wells that produced gas in March reported water production volumes to NMOCD.(33)

The upsurge in coal-bed methane production in the San Juan Basin has stretched waste water disposal capacity and necessitated the installation of hundreds of miles of new produced water pipelines. Permitted surface disposal capacity in the New Mexico portion of the basin was 1.25 million barrels in mid-1989.(34) About 80,000 barrels of that capacity is temporarily unavailable because the receving facility was shut down by NMOCD recently as a result of a hydrogen sulfide release.(35) In the three-month period of December 1989 through February 1990, 33 active injection wells disposed of 3.4 million barrels of water.(36) Together, commercial and centralized surface disposal facilities and injection wells located in New Mexico had barely enough capacity to handle the water that was generated from the coal beds alone during the first quarter of the year. Some operators shut in a few of their coal-gas wells until new disposal capacity is constructed.(37)

In the Colorado portion of the basin, 13 injection wells were operating on Southern Ute Indian lands as of May 30. Another 22 were under construction or pending permitting by the U.S. Environmental Protection Agency.(38) One facility was recently permitted to discharge coal-bed water treated by reserve osmosis to a tributary of the Animas River.

Policy and Regulatory Implications of Coal-Bed Methane Production

That the pace of gas development in the San Juan Basin has picked up considerably in the past 18 months is readily apparent to most residents, and even to frequent visitors to the area. Drill rigs are more numerous in the Bondad, Cedar Hill and Navajo Lake areas. Produced water trucks pound the major highways and dirt roads of the gas fields in numbers not seen since the oil and gas boom period of the early-1980s. Trenches for new gas and produced water pipelines are cutting ribbons across the piñon and juniper highlands. The flurry of development is directly related to the gas industry's desire to drill and complete coal-bed methane wells before the tax credit for nonconventional fuels expires at the end of the year.

The rapidity of coal-bed development in the San Juan Basin has forced regulatory agencies to prioritize processing of applications to drill at the expense of ongoing compliance and enforcement activities or environmental protection programs, such as well plugging and abandonment. BLM officials in Farmington have said they cannot conduct compliance and process APDs at the same time. They also say that the agency's policy is not to defer action on new coal-bed gas leasing until the backlog of permitting and compliance tasks is whittled down.(39)

The emerging evidence that implicates coal-bed methane development and production in the widespread contamination of ground water in the San Juan Basin demonstrates the urgent need for new policies and regulatory programs to prevent additional natural gas pollution of ground water and to remediate existing contamination. The evidence also points to the need for state and federal regulatory agencies to take immediate and stringent preventive actions while the problem continues to be studied. As such, citizens groups and public-interest organizations are calling for a wide range of new policy and regulatory initiatives to address the consequences of coal-bed methane development. While the suggested initiatives that follow are predicated on conditions prevalent in the San Juan Basin, many may be equally applicable to operations and impacts occurring in other parts of the nation where coal gas is being produced:

•MULTIJURISDICTIONAL PLANNING AND COOPERATION. State and federal regulatory agencies must cooperate and communicate more frequently and regularly on matters that transcend political, geographic, or jurisdictional boundaries. The impacts attributed to natural gas development in general and to coal-bed methane production in particular cut across boundaries in the basin. Yet some agency officials in Colorado appear to be acutely unaware of the scientific basis for the actions and orders of their counterparts in agencies in New Mexico.

•CUMULATIVE ENVIRONMENTAL STUDIES. Cumulative, basinwide environmental analyses should be conducted by a multijurisdictional team. To date, there are no firm figures on how many coal-bed methane wells are likely to be completed and producing by the end of the year on private, state, federal, and Indian lands in the basin. Neither is there a clear understanding of the cumulative impacts this development will have. Environmental impact statements currently are being prepared by separate units of BLM and the Forest Service are not likely to consider coal-bed methane development impacts that occur outside of the jurisdictions administered by the agencies. While statutory changes may be needed to grant federal agencies authority to enter into cooperative environmental studies with states and Indian tribes, agencies should adopt policies that promote and implement such cooperative studies now, rather than wait years for the law to be changed.

•CEMENTING OF EXISTING GAS WELLS. Gas wells that penetrate the Fruitland coal beds should be cemented throughout the basin. Cementing should also be continuous through the fresh-water zones that overlie the gas-producing formations. Such remedial actions are relatively inexpensive and are being implemented by operators in the New Mexico portion of the basin. Remedial cementing of this type has not been ordered by agencies in Colorado.

•PRE-LEASE ENVIRONMENTAL AUDITS. In the absence of cumulative, basinwide environmental analyses, comprehensive environmental audits should be performed for all new coal-bed methane leases. Such audits should consider the complete range of potential impacts from produced water disposal, gas migration, emissions of greenhouse gases like CO_2, and the construction of roads and river crossings.

•MORATORIA ON NEW LEASING. A moratorium on new leasing would be a prudent and useful step, especially for state and federal agencies which have authority to temporarily suspend a lease on lands that are within their jurisdictions. A moratorium would allow the regulatory agencies to catch up on other permitting and compliance activities at the same time that the impacts of coal-bed methane development are assessed. Plugging of abandoned oil and gas wells and integrity testing of gas-producing wells could be program priorities during the period of a moratorium.

•CORRECTIVE ACTION AND COMPENSATION FUND. Residents whose wells have been contaminated are faced with an impossible burden of proof in sustaining a private cause of action against a particular gas-well operator or a cadre of operators. Even when a private party is successful in a damage case in court, the award does nothing to remediate the contaminated ground water. A fund needs to be created to compensate residents for polluted water supplies and damaged croplands. The fund could also finance research and remedial actions to reduce or eliminate gas contamination of fresh ground water. The fund would logically come from a surcharge on revenues generated from the production of natural gas.

•ONGOING PRIVATE WELL TESTING. As long as natural gas is being detected in private wells in the Animas River valley, periodic free testing of domestic water should be continued. Community water fairs should have the capability of testing for organic vapors and aromatic VOCs. State and federal agencies should pool their resources to insure that gas samples can continue to be analyzed by USGS for chemical and isotopic composition.

•LOCAL LAND-USE CONTROLS. Local governments should exercise their land-use authorities to regulate aspects of oil and gas operations that are not covered by state or federal regulations. Surface disturbance and land-use incompatibility are two relevant issues for local governments.

•PRODUCED WATER MINIMIZATION AND DISPOSAL ASSURANCE. Requirements for producers to minimize or reuse water produced from coal beds should be incorporated in pre-lease audits or in applications to drill. At a minimum, agencies should require operators to demonstrate that adequate disposal capacity is available prior to gas-well completion. Permitting of produced water haulers also is necessary to prevent illegal dumping when disposal space is unavailable.

•DISCONTINUATION OF THE TAX CREDIT. The tax credit for coal-bed methane development should not be extended, at least not without concomitant requirements for the assessment of environmental impacts. The purpose of the credit — to spur development of domestic sources of energy — is no longer served in an era of surplus natural gas. The credit also encourages development that otherwise would not occur under normal market conditions.

Conclusions

The contamination of alluvial ground water in the Animas River valley of New Mexico and Colorado by thermogenic natural gas is related in part to the recent upsurge in the drilling for and production of coal-bed methane. Gas from the coal seams of the Upper Cretaceous Fruitland Formation has migrated nearly 3,000 feet into domestic water wells and cathodic protection holes and has charged up the surface casings and Bradenheads of producing gas wells. The gas has migrated upward via the uncemented portions of gas wells that penetrate the Fruitland. The extent to which leaks in the casings of either Fruitland wells or wells that produce from deeper, sandstone formations, or both, has not been determined. Remedial measures ordered by regulatory agencies are limited to workovers of gas wells that penetrate the coal seams. The large volumes of water produced from the coal seams vary greatly in dissolved solids content, are rich in bicarbonate and sodium, and exhibit concentrations of barium, gross alpha radioactivity, and total radium that exceed drinking water standards. Produced water from coal beds in the basin is stretching the available disposal capacity and forcing some operators to shut in their Fruitland coal wells. New policies and regulations, such as basinwide environmental analyses, moratoria on new coal-bed methane leasing, establishment of a corrective action and compensation fund, are needed to address the impacts of coal-bed methane development.

Acknowledgments

The author appreciates the ongoing access he has to the files, data, and personnel of the New Mexico Oil Conservation Division. And he is especially grateful for the cooperation, assistance, and perseverance of residents of the Animas River valley. Finally, he wishes to recognize the valuable assistance of SRIC administrator Don Hancock in the review of this paper.

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13. While those results have not been published in the scientific literature, Mr. Rice told the author (personal communications, June 22 and 27, 1990) that the results will be described in an upcoming USGS publication. He said the data are reliable and indicate that natural gas has migrated from deep formations as a result of either natural conditions or activities associated with drilling and completing gas wells.

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THE POTENTIAL FOR SOLAR DETOXIFICATION OF HAZARDOUS WASTES IN THE PETROLEUM INDUSTRY

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Abstract

The generation of hazardous waste from industrial processes is a national problem. Due to the incidence of impacts on the public health and the environment, the importance of appropriate hazardous waste treatment has experienced an increasing level of attention over the past two decades. Although significant advances have been achieved in the disposal and destruction of these wastes, there remains significant room for improvement in the destruction efficiency of waste detoxification technologies, their cost, and the environmental impacts of waste detoxification processes themselves. Currently, the U.S. Department of Energy through its national laboratories is performing R&D in the use of solar energy to detoxify hazardous wastes. This paper discusses the process of solar detoxification of hazardous waste and the potential for utilizing this process in the petroleum industry.

Introduction

The U.S. Environmental Protection Agency (EPA) recently released the data for its Toxic Release Inventory (TRI) for 1988. During the year, 19,762 industrial plants in the U.S. released 4.57 billion pounds of toxic chemicals into the environment. The bulk of this (53.2%) was released to the air, the remaining was injected to underground wells, released to landfills or dumped into rivers, lakes, streams and other bodies of water. In contrast to chemical releases to the environment, 0.57 billion pounds were transferred to wastewater treatment facilities and 1.10 billion pounds were transferred to other treatment and disposal facilities.[1]

The chemical industry (SIC 28)[2] is by far the largest producer of toxic waste, generating roughly 50% of those chemicals reported on the TRI. Other industries which produce large quantities of toxic wastes include the metals industries (SIC 33, 34), rubber and plastics industries (SIC 30), and the paper and allied products industries (SIC 26). The petroleum industry (SIC 29) is among the top

10 generators of toxic waste in the U.S. The EPA, TRI reported that total releases for SIC 29 during 1988 were 109,344,966 pounds, or 2.5% of total toxic releases in the U.S.[3]

Without proper treatment, toxic emissions can produce serious consequences. Air pollution has become an increasing health and environmental hazard in many of the nation's urban areas. In some regions of the nation, water pollution is jeopardizing marine life and depressing local industries. The pollution of groundwater with toxic or cancer-causing chemicals has, in some extreme cases, forced residents to obtain drinking water elsewhere. In several tragic cases, when residents were unaware of the contamination and continued consuming the contaminated water, they suffered serious health effects.

In 1976, the Resource Conservation and Recovery Act (RCRA) was passed to provide an initial set of guidelines and regulations to improve the treatment and disposal of waste. In 1979, however, EPA estimated that still only 10% of hazardous wastes produced in the U.S. were managed in an environmentally sound manner. Subsequently, Subtitle C of RCRA was developed to establish a "cradle-to-grave" management system for hazardous waste to ensure that mismanagement did not continue. Subtitle C set forth a program to: identify hazardous waste; regulate generators and transporters; and regulate and permit owners of treatment, storage and disposal facilities. The Subtitle C program constituted one of the most extensive and comprehensive set of regulations that EPA had ever developed. It is within this program that U.S. industries generating hazardous wastes must operate.

Waste treatment and the level of destruction efficiency has improved since institution of the RCRA. However, the waste disposal or treatment techniques used by various U.S. industries, such as landfilling or incineration have sometimes provoked as great a concern as the hazardous wastes themselves. Waste treatment processes can often be highly energy intensive resulting in extensive levels of pollutants during the transfer, treatment, and disposal processes. Solar detoxification, however, presents a relatively clean option which can augment future hazardous waste treatment activities.

The following is a brief overview of specific types of hazardous wastes produced in the petroleum industry and current treatment techniques being utilized. The solar detoxification process is then described as is its potential for applications in the petroleum industry.

Hazardous Waste in the Petroleum Industry

Petroleum industry processes encompass a broad range of activities including exploration and production, refining, storage, and distribution. Throughout these process, wastestreams are generated -- many of which are classified as hazardous. These wastestreams can be in the form of wastewater, acids, tank bottoms, separator and cooling tower sludges, and other process wastestreams.

Many of the hazardous wastes generated in the refining segment of the industry are also present in other segments of the industry as well.

These hazardous wastes typically contain metals such as lead and chromium, or chemicals such as chloroform, toluene, 1,2-dichlorethane or cyanides, making them toxic and potentially harmful to both human health and the environment if not properly managed. Table 1 below, lists wastes from refining process, which are classified as hazardous under the RCRA. These wastes are also generated throughout other stages of petroleum industry processes.

Table 1
Appendix VIII Constituents found in Refinery Wastes

Antimony	2,4-dinitrophenol
Arsenic	Di-n-octylphthlate
Benzene	Fluoranthene
Benzo(a)pyrene	Hexachlorobenzene
Beryllium	Lead
Bis(2-ethylhexyl) Phthalate	Mercury
Cadmium	Naphthalene
Chloroform	Nickel
2-Chlorophenol	4-nitrophenol
Chromium	Pentachlorobenzene
Chrysene	Phenol
Cyanides	Selenium
DDE	Silver
1,2-dichloroethane	Tetrachloroethylene
Dichloroethylene	Toluene
Diethyl Phthalate	Vanadium
2,4-dimethyl phenol	Zinc
4,6-dinitro-o-cresol	

Source: The Land Treatability of Appendix VIII Constituents Present in Petroleum Industry Wastes, American Petroleum Institute Pub. No. 4379.

The above toxics, found in petroleum process wastes, are among the chemicals ordered by the EPA's Toxic Release Inventory (TRI) and contribute to the industry's portion of total U.S. TRI releases. Table 2 below shows the breakdown of petroleum industry (SIC 29) releases to the environment as well as wastes transferred out, for 1988. The same data are shown for the total U.S. inventory. In all, the petroleum industry accounted for 2.4% of toxic chemical releases to the environment.

Table 2
Releases and Transfers of All
Toxic Chemical Release Inventory Submissions
(pounds)

	Total U.S.	Petroleum (SIC 29)	% of Total U.S.
Air Releases-	2,427,570,103	69,118,376	3.0%
Discharged to Water-	361,594,238	4,147,541	1.2%
Underground Injection-	1,215,343,908	30,299,195	2.5%
Releases to Land-	561,556,882	5,779,854	1.0%
Total Releases-	4,566,065,131	109,344,966	2.4%
Discharged to:			
Municipal Wastewater Treatment Facilities-	570,551,308	13,887,417	2.4%
Other Treatment and Disposal Facilities-	1,104,414,307	10,826,337	1.0%

Source: 1988 Toxic Release Inventory, Releases and Transfers by Industry, Environmental Protection Agency, April 1990.

Of total TRI generated wastes by SIC 29 companies, roughly 82% was released to the environment. Of this amount, about 63% was released to the air and about 28% released through underground injection. The remaining releases to the environment were in the form of releases to land (5.3%) and discharges to water (3.8%). This pattern of toxic releases in the petroleum industry follows similar patterns as those for U.S. industry in general.

The remaining 18% of petroleum industry generated wastes were transferred-out either to municipal wastewater treatment facilities, or other treatment and disposal facilities. However, transfers-out by the petroleum industry are significantly lower than the national norm. On the whole, U.S. industry transferred-out roughly 27% of TRI wastes to treatment facilities.

Although "releases to the environment" may imply indiscriminate emissions or waste dumping, most of the wastes generated by the petroleum industry are managed via approved treatment and/or disposal processes. These processes, when properly administered and managed, are designed to reduce or eliminate the environmental and health threats posed by specific hazardous wastes. Treatment and disposal processes utilized by the petroleum industry include:

Landfilling- Landfills store wastes in constructed or natural excavations. They use a combination of liners and leachate-collection systems to control the migration of the wastes or their byproducts. When a landfill is full, it is covered with impermeable material such as compacted clay.

Incineration- In this process, wastes are burned (oxidized) at high temperatures in enclosed chambers.

Deep-well Injection- This process isolated hazardous wastes in deep underground reservoirs surrounded by impermeable rock.

Surface Impoundment- In this method, wastes are deposited in open basins that have been excavated in the ground. The basins are lined with impermeable materials. In most cases, surface impoundments are used only for temporary storage or as treatment areas for wastes that will be disposed of through other means.

Chemical Treatment- Chemical processes can change the composition of certain hazardous wastes -- such as acids and sludges -- rendering them non-hazardous. Chemical treatment processes include: neutralization (pH adjustment), precipitation, oxidation, and chemical fixation/solidification.

Land Treatment- The most widely-used treatment and disposal process, land treatment entails spreading wastes over the soil surface allowing the soil and natural soil organisms to break down hazardous wastes. It is considered a treatment and disposal method since a fraction of the waste does not decompose, but instead becomes immobilized in the soil.

None of these techniques is suited for each type of hazardous waste generated in the petroleum industry. Most facilities use a combination of these techniques in managing hazardous waste.[4] Each of these techniques requires constant site treatment, monitoring and if necessary remedial action, to remain a viable alternative for the industry's waste disposal options.

Solar Detoxification Technology

An interesting waste treatment option is undergoing R&D at the Department of Energy. In the past six years, solar detoxification of hazardous waste and contaminated water has been successfully tested and in the near future may be able to augment current petroleum industry hazardous waste treatment processes.

Solar detoxification can offer a clean and effective option for decontaminating volatile organic compounds (VOC) in drinking water supplies or chemical wastes. It will not require the intense use of energy necessary for some current waste treatment and disposal technologies and it should be available for on-site applications, depending on the type of waste as well as other relevant conditions.

For the past six years, the U.S. Department of Energy (DOE) has been funding solar detoxification R&D at the Solar Energy Research Institute (SERI) in Golden, CO and Sandia National Laboratories in Albuquerque, NM. Because of a recent reorganization of the DOE Conservation and Renewable Energy Program, this technology area is now under the lead of the Waste Material Management Division. The solar detoxification program was initiated due to the growing hazardous waste problem both within U.S. industry and U.S. Government facilities as well as to provide a possible alternative to existing detoxification techniques.

Two solar detoxification processes are being investigated -- solar detoxification of wastewater and destruction of hazardous chemical waste. The primary drive behind the solar detoxification technology and introducing it to the marketplace is its added advantage over conventional technologies. For example:

- When augmented with existing techniques, solar detoxification can enhance the volume and quality of waste destruction capabilities.

- Tests have achieved 99.99999% dioxin destruction at 750° -- exceeding the destruction efficiency of conventional technologies as well as EPA destruction efficiency requirements, while requiring far lower temperatures.

- The solar detoxification process destroys the waste completely rather than transferring it to another medium (i.e. air or water emissions, landfills, etc.).

- Solar detoxification of contaminated wastewater is faster than conventional technologies. Demonstrations have achieved 85% oxidation of trichloroethylene (TCE) in a single pass (2.5 minutes) at 27 gpm. TCE is the most commonly found contaminant in almost 10% of U.S. drinking water supplies.

- Solar detoxification systems can be mobile and utilized on-site at industrial or government facilities.

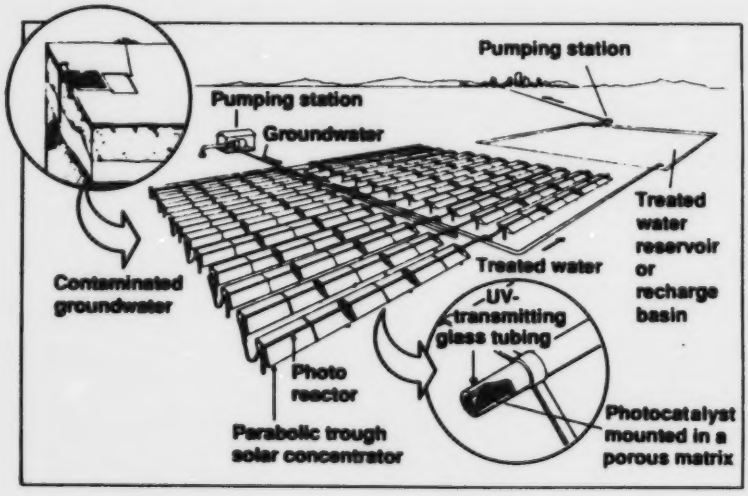
- Solar detoxification does not require the intensive use of fossil fuels or chemicals as do other methods such as incineration or chemical treatment.

The solar detoxification processes for wastewater treatment and chemical wastes utilize a combination of high-energy photons providing a quantum effect and infrared photons providing thermal energy resulting in effective destruction of

chemical wastes. Many industrial solvents have been destroyed and preliminary testing has indicated that solar detoxification may also remove some heavy metals from water.[5]

Solar Wastewater Decontamination- The DOE solar detoxification program has established solar water decontamination as one of its major priorities. In this process, sunlight is focused on a reactor through which the contaminated water is flowing. Ultraviolet (UV) energy in the concentrated beam activates a catalyst in the waste stream. This results in the formation of very aggressive oxidizers known as free radicals, which in turn break down the organic wastes into treatable nonhazardous products such as carbon dioxide or dilute hydrogen chloride.

Figure 1 below is an illustration of a solar detoxification system for groundwater which would utilize Sun-tracking parabolic troughs. Contaminated water would enter a UV glass tube placed at the focus of this concentrator, at one end of a trough containing the photocatalyst, and exit at the opposite end of the trough as processed decontaminated water which could then be transferred to municipal reservoirs. Solar detoxification systems developed at SERI and Sandia have successfully destroyed TCE at a faster rate than conventional processes and at lower temperatures. Current plans are to address system scale-up issues, assess competitiveness, and to have commercially-ready systems by the mid-1990's that will be capable of processing water containing solvents, dyes or pesticides.



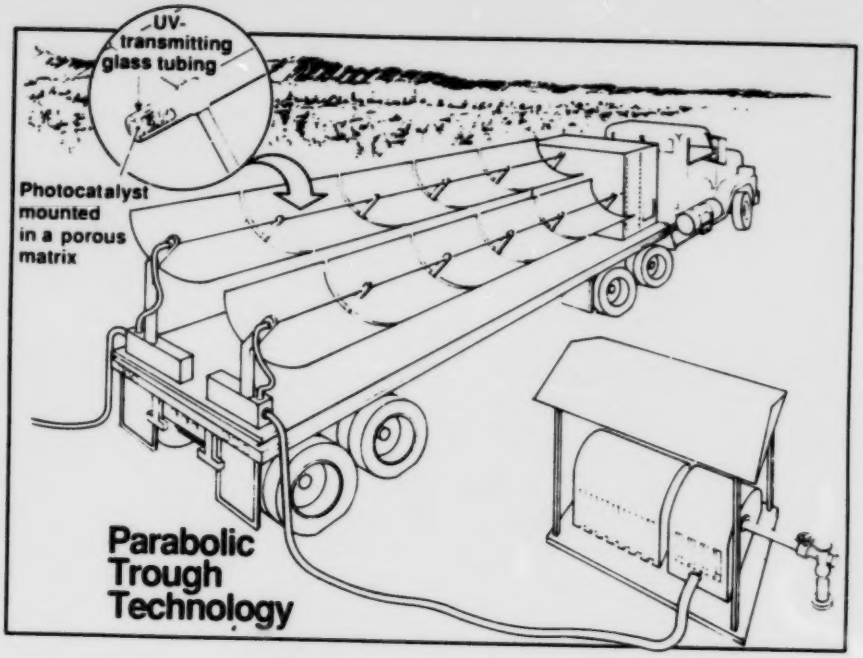
A significant advantage of this process over conventional processes is that this process destroys the contaminants in a single step without the need for first removing them from the water. Once cost-effective, solar water decontamination systems should be commercially marketable and have far less environmental and energy costs than conventional wastewater treatment technologies.

Solar Destruction of Chemical Wastes- The solar destruction of hazardous chemicals is similar to conventional incineration. The solar detoxification process occurs in two steps within a reactor of a concentrating solar energy system -- such as parabolic dish, central receiver, or a solar furnace reactor. In a typical application, a toxic waste is exposed to a focused beam of solar energy concentrated 1,000 or more times the intensity of normal sunlight and heated to 700° to 1,000°C. Part of the solar beam provides low-energy photons in the infrared and visible parts of the spectrum to heat the chemical wastes. A second part of the beam provides a quantum component or high-energy photons in the UV region to break the chemical bonds and destroy the molecules.

The combination of thermal and quantum energy results in a more complete destruction of the toxic chemicals at lower temperatures than those required using conventional incineration. For example, in 1989 tests to destroy a dioxin (1,2,3,4-tetrachlorodibenzo-p-dioxin) achieved a greater than 99.99999% destruction efficiency at 750°C. Conventional incinerators, however, would require temperatures above 1,000°C to achieve the same level of destruction efficiency. Plans are for having commercially-ready systems by the late-1990's which are capable of destroying low-Btu and hazardous chemicals such as dioxins and PCB's.[6]

Once commercially viable, solar hazardous waste detoxification systems for chemical waste and contaminated water, will have several advantages over conventional technologies. For example, the solar detoxification process reduces temperature requirements by 300° to 400°C over those required in conventional incinerators. In addition, the photolytic process reduces the toxic products of incomplete combustion remaining in the exhaust stream and eliminates the emissions generated by burning fossil fuels.

Moreover, mobile detoxification units are being researched for solar water decontamination. These mobile units, depicted in Figure 2, can be trailer mounted systems that could be utilized at various industrial or remediation sites to perform decontamination testing and evaluate the potential for solar decontamination in a variety of situations. By performing the process on-site, the costs and environmental impacts associated with off-site transfer are also eliminated. In addition, the mobile units can function to educate potential users about solar detoxification technology. Eventually, the mobile units should be commercially available to perform full-scale decontamination services.



Importance to the Petroleum Industry

Ongoing testing has proven that a number of hazardous chemicals can be potentially handled in an effective manner utilizing solar detoxification. Table 3 lists the most common toxic and noxious chemicals found in groundwater which are both known toxins and where decomposition by natural sunlight in conjunction with a catalyst has been proven. Several of these toxics are generated in refinery process wastestreams (Table 1). These include 1,2-Dichlorethane, Chloroform, Toluene, and Phenol. Most of these are on the EPA's priority list of toxic wastes threatening the nation's groundwater. They are also among the Solar Detoxification Program's list of priority toxics. In addition to the wastes listed in Table 3, there are numerous other toxics (chemicals and metals) found in petroleum industry wastestreams which can potentially be destroyed using solar detoxification. These include: cyanides and benzene as well as metals such as lead, nickel, beryllium, cadmium, chromium, mercury, vanadium, zinc, and selenium.

Not all wastestreams generated in the petroleum industry will be viable for treatment using the solar detoxification process. However, solar decontamination of water as well as solar detoxification of hazardous chemical wastes should present viable options for treatment of refinery wastewater, waste streams which may otherwise end up as stormwater run-off silt, as well as other hazardous liquid wastes which may otherwise be chemically treated, incinerated or injected

Table 3
Toxics Found in Petroleum Industry Wastestreams with Potential for Treatment by Solar Detoxification*

1,1-Dichlorethane	1,2-Dichlorethane	Carbon Tetrachloride
Trichloroethylene	Perchloroethylene	Ethylene Dibromide
Dichloromethane	Chloracetic Acid	Chloroform
Ethylene Glycol	Toluene	Chlorobenzene
Salicylic Acid	Phenol & Chlorophenol	2,4,6, Trinitrotoluene

* Those toxics which are both: 1) listed by API as found in petroleum refining waste streams; and 2) listed among the priorities for the Solar Detoxification Program.

underground. Moreover, the ability to provide mobile or on-site solar wastewater decontamination can also prove to be an asset for refineries and other industry facilities which may not have cost-effective access to conventional treatment or disposal facilities.

Current program goals are to have commercially-ready solar water decontamination systems in-place by 1995 with throughput costs of $0.40 - $1.00 per 1,000 gallons. In the area of solar detoxification of hazardous chemical waste, program goals are to have the technology commercially viable by the late 1990's with a cost of $300 - $500 per ton.[7]

Endnotes

1. "EPA Announces 1988 TRI Figures", Environmental News, Environmental Protection Agency, April 19, 1990

2. Federal Standard Industrial Classification (SIC) codes: SIC code 28- Chemical and allied products industries; SIC 33- Primary metal industry; SIC 34- Fabricated metal products, except machinery and transportation equipment; SIC 30- Rubber and miscellaneous plastics products; SIC 26- Paper and allied products; SIC 29- Petroleum refining and related industries.

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A PRACTICAL APPROACH TO ENFORCEMENT OF HEAVY OILY WASTE DISPOSAL

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ABSTRACT

Heavy Oil Production Operations in Alberta have become quite efficient at coaxing viscous crude from the earth. One problem which has remained constant, however, is the need to remove and dispose of the reservoir sand produced in association with the heavy oil. This paper looks closely at the role enforcement plays in heavy oil waste management practices within the province of Alberta. As part of this we will examine the size and dimension of sand production; where it is typically found within the production chain; various sand cleaning methods; handling and storage systems; as well as some selected disposal techniques. A review of key legislation and policy used by the Energy Resources Conservation Board will center on characterization (toxicity) of the waste, environmental impact, hydrocarbon reclaiming and continued need for research into new technology. Also addressed will be the application process which Heavy Oil Operators must follow in order to meet the requirements for satisfactory disposal of this waste product.

This paper will also look at various mechanisms used to maintain and upgrade the guidelines that are in effect. The views of local Government Authorities (County and Municipality Districts) and the general public will be presented as each plays an important role in gauging any apparent or perceived consequences related to oily waste disposal practices.

The primary goal of this enforcement policy is to provide an effective yet practical approach in dealing with this problem. The workability of this system will be briefly illustrated in examples which demonstrate the positive aspects and commitment to an acceptable system by all concerned parties.

INTRODUCTION

There is an old saying that for some dogs, their bark is worse than their bite. Unfortunately this often is the case facing government departments or legislative regulators when trying to perform their duties as administrators of the public interest in areas such as resource development, manufacturing and other heavy industry. Mountains of acts, regulations, edicts or other policy directives are little comfort to society and all too often the environment if their enforcement cannot be performed in an effective and timely manner.

In the Province of Alberta, the Energy Resources Conservation Board (ERCB), with over fifty years of experience as a regulator and enforcer of The Energy Industry, long ago realized that full compliance of any legislation must be accompanied by a practical and reasonable enforcement program. Without question, a large proportion of the success and reputation earned by the ERCB over its history is attributable to the way in which it is structured. There are eight statutes or acts which give it broad powers but it is the process which is undertaken to interpret these various statutes used to formulate a policy which provided the basis for industry and public acceptance.

The ERCB is structured as a quasi judicial government organization funded jointly by industry and government. Its main purpose is the regulation of Alberta's Energy Industry. Its mission is to facilitate and regulate the responsible development and careful conservation of Alberta's energy resources in the public interest. With a key role as a facilitator, being that the crown which is the province, owns the vast majority of the energy resources, the ERCB and industry often share the same goal when it comes to energy development. In so doing, the ERCB attempts to bring fairness and a sense of balance to the often times, conflicting needs, concerns and perceptions of the people of Alberta, their government and the energy industry.

The ERCB is headed by professionally qualified Board members, six at the present time, each appointed by the Alberta Cabinet, usually from within the organization but not always. In order to carry out its responsibilities, the Board employs a staff in excess of 700, including engineers, geologists, economists, field inspectors and many other kinds of technical experts and support staff. The ERCB staff is divided into 16 departments located in the ERCB's Head Office in Calgary, with about sixteen percent of the compliment situated in eight field offices throughout the province where much of the actual enforcement takes place.

The factors which have a role in converting a formal and generalized statute, into an effective and practical enforcement policy will be examined later. Prior to this, it is important to focus on one small isolated case to provide the background in how this process occurs and why it appears to be an obvious and natural one.

HEAVY OIL PRODUCTION

A small but important part of Alberta's extensive oil and gas industry is the heavy oil sector situated mostly in the northeastern portion of the province. There are about 50 active operating companies, however,13 of these are responsible for 90 to 95 percent of the total heavy oil production. At peak production the major companies were operating over 2100 individually tanked wells. These wells simply pumped their effluent directly to tanks at each well site with production then trucked to central treating facilities. Added to these are over 1400 flowlined wells, wells which are pipelined to one of approximately 63 treating batteries and satellites.

Heavy oil is of course referred to as heavy because of its high viscosity and low gravity which range anywhere up to 22 degrees api or in metric units this relates to a density greater than 920 kg/m3. With such a wide variance in gravities or density, industry has had to become very creative and innovative in its recovery techniques. These have involved exotic tertiary recovery schemes such as firefloods, steamfloods, solvent floods, electromagnetic stimulation and in the oil sands area it is actually open pit mined although we will not be including the oil sands or bitumen production into this discussion. In the fifties, there was even talk of setting off a nuclear device in some reservoirs to create instant caverns of heated heavy oil. For some reason this method did not get approval.

Regardless of which recovery method is used there seems to be one inherent common problem that operators must deal with on an ongoing basis. This is of course the produced reservoir sand which is carried with the thick heavy oil to surface and settles out within a number of points throughout the production and treating chain. To compound this it appears from statistics that the individual average sand production per well increases throughout the life of that well so any hopes that in time this volume would diminish as the wells and fields mature is certainly an incorrect assumption.

The majority of the reservoir sand tend to settle in the storage tanks at the individual well sites and in treater vessels at the central treating batteries and satellites. At peak production this would be approximately 55,000 and 20,000 cubic yards (40 and 15 10^3 m^3) per year respectively. This material by far constitutes the

largest problem heavy oil operators and in part regulators have to deal with not only from the point of removing this material from the production chain but more critically its appropriate disposal. With each well producing an average of 20 cubic yards (15 m^3) of sand each year, tank cleaning operations are a very common and highly scheduled occurrence within the heavy oil patch (Fig. 1).

SAND RECOVERY, TANK CLEANING

Cleaning tanks is almost an industry in itself and quite competitive at that with a number of commonly used tank cleaning methods. Probably the most common of these goes by the unflattering name of the "goon spoon" tank cleaning method. In this method the tank is first emptied of as much fluid as possible then a large bell hole is dug with a backhoe immediately adjacent to the manhole access of the storage tank. A metal drum or tub is lowered into the bellhole so that when the access plate is removed the contents of the tanks will drop into the tub where the fluids and solids are gathered by vacuum trucks and hauled to a central storage area known as an ecology pit. The "goon spoon" originally got its name from a specialized attachment to the backhoe arm which resembles a large spoon which is inserted into the tank to pull out the sand sitting at the base of the tank. Today, more commonly used is a wash water, usually warm production water, which helps in flushing the sand from the tank and making a slurry that the vacuum trucks can more easily handle. This method is used quite extensively because once the tank is cleared of the sand accumulation it allows for entry into the tank by maintenance personnel to inspect the fire tube or any other obvious defects within the tank's interior. When the operation is complete the cover plate is put back into place, the tub removed and the hole filled in. The entire job takes about three hours.

The second most common practice is the use of a stinger apparatus. Prior to removal of the sand in this case the tank is flooded with warm produced water, injected near the tank's base. This helps to lift the majority of the oil in the tank above the level of the sand. The oil is then drawn off and transported to the central treating facility. With most of the oil removed from the tank a probe is inserted into a specially designed receptor at the base of the tank. The probe which is usually a 4 inch pipe also has a 1 inch, high pressure water nozzle inserted through it. Using high pressure water jets the sand is then made into a slurry and pumped out through the annular space between the 4 inch probe and 1 inch wash nozzle directly into a vacuum truck. Here again the vacuum truck would then take the contents to a central battery or processing area for storage, under proper conditions, until the sand can be disposed of at a later date. Normally with this method the sand is a much cleaner product than what is gathered from the "goon spoon" method and is often piled on an apron adjacent to the

ecology pit. This will allow any leachate to flow into the ecology pit itself. Although this is a less manpower intensive method, it does not facilitate the inspection of the internal components of the storage tank itself.
An additional method of tank cleaning is by using specialized mechanical equipment built solely for this purpose. After all excess liquids are removed from the tank this system uses a number of augers and water jets to remove the sand directly into a sealed tank truck. This equipment is able to move up to the storage tank and seal itself around the open manhole access without having to dig a bellhole. Again, because access to the inside of the tank is through the manhole, an inspection of the tank interior and fire tube can take place. The waste sand recovered from the tank is again transported to the ecology pit for storage prior to its disposal.

SAND STORAGE

As noted earlier, most of the sand recovered from the well site tanks and also process vessels at the treating facilities is stored in ecology pits or desand tanks. The ecology pit is a concrete lined structure that must meet strict guidelines for its construction and monitoring. The design must accommodate an unloading area and have the ability to clean the solids from the pit by mechanical means if necessary. Monitoring is accomplished primarily with observation wells which intersect a weeping tile loop. The wells must be sampled regularly and analyzed for not only oil and grease but for total organic carbon, electrical conductivity, pH and major ions such as calcium, magnesium, sodium, potassium, nitrate, sulphate and chloride. The results of these analyses must then be submitted the ERCB.

One of the great mysteries seems to be why it was called an ecology pit as usually its content seems to belie its name. This structure is often used for not only collecting the produced sand retrieved from storage tanks but also oil spill material and debris associated with lease clean up and housekeeping operations.

The desand tank on the other hand is an intrical part of the heavy oil operations treating systems. Most vessels and tanks within the production battery treatment process are equipped with internal flushing systems which are regularly used to clean away any sand build up that may be occurring within those vessels to the desand tank. Free liquids are frequently skimmed from the desand tank and reintroduced into the process system. The sand and other solids are then subject to the same disposal considerations as the contents of the ecology pits.

SAND DISPOSAL

When it comes to disposal techniques there are as many as there are tank cleaning methods. The most commonly used ones in the northeastern part of Alberta is to dispose of the oily sand waste material to municipal or county roads where it is used as a dust suppressant or road surfacing material. Another alternative, depending on the quality of the sand, might be to use it in the actual construction of a new road bed or in monitored landfill situations. A novel practice that is gaining popularity is the downhole injection of the sand as a slurry to a present or past producing horizon. Some work is also progressing on the use of new salt caverns which are created and used to dispose of the produced sand bi-product simultaneously. There also continues to be research and development into various processes which will remove virtually all of the hydrocarbons and chlorides from the waste leaving a relative clean, environmentally friendly sand which would have a number of potential uses in other industries where a fine silica sand, similar to this sort of material, is needed. The income that may be generated by this new market would offset in part the high cost of transporting and processing the sand.

With this background now covered we will focus on the road disposal techniques only at this time because it is at present the most common practice and of the greatest concern to the ERCB and industry in as much as the potential impact it may have on the public or the ecosystem.

The biggest hurdle operators face in dealing with the produced sand is its disposal. By far the disposal of choice for a number of reasons over the years has been to use the material as a dust suppressant or a sort of cold paving mixture in road surfacing. The popularity for this method stems from the proximity of roads to the oily sand storage areas as well as the high demand by some local governments (counties, municipalities or improvement districts) for this free material, its perceived economic advantage to operators and lack of any other viable technology for many years. It is a perceived economic advantage because there were no other methods to compare it against and operators felt they could live with the costs of disposal related to this method.

APPLICATION AND APPROVAL PROCESS

Let us now examine how the ERCB's enforcement program works within this small specified area. In this situation as in almost all areas regulated by the ERCB, the application for approval to conduct almost any operation is the backbone of a policy which has a high degree of compliance and certain assurances that all requirements will be met.

In order for a company to get approval for the disposal of the oily sand waste it must follow a well defined application process outlined in the ERCB's Informational Letter IL85-16. This informational letter, as is the case with many others, clarifies and consolidates the ERCB's policy regarding the matter of handling, storage and disposal of oily wastes as referenced in its regulations. From the onset this document makes it clear that the ERCB has reservations about repeated disposal of oily wastes by application to Municipal or other roadway surfaces and believes that this disposal technique is not the long term solution to the disposal problem. Not withstanding this, and knowing full well that other technologies are limited, even more so in 1985 when this IL was written, the informational letter goes on to list the conditions that must be met when using the material as a dust suppressant or as a road surfacing material. The criteria and characterization requirements are very general and, as such there were no specified limits on each of these elements as standards were not well defined or even in existence (Fig. 2). Variances in quality of the material could then be handled on a site specific basis with the responsibility resting with the company to outline an environmentally safe disposal technique. The ERCB would then evaluate the application on its merits and may then add as a condition of approval, any additional mitigative measures as further safe guards. An estimated total volume to be disposed of and location of the disposal, must also be provided. In addition, once the oily waste is approved for disposal, the operator must provide the appropriate ERCB Area Office with consent of the local authority (Municipal District, improvement district, County, etc.) accepting the waste. Ensuring proper application operations would then become the responsibility of the local authority with most, if not all, of the costs borne by the oil company.

Each application not only addresses the reasonable environmental impact of the disposal technique through the characterization of the material but will also require the company to address its future disposal requirements. The operator must show that a real and concerted effort is being made towards alternate forms of disposal to replace the roads as the primary end point for their wastes. This is important because it allows for a natural progression of having to follow through with new research and development while continuing to allow a relatively easy access to an outlet for the waste byproduct. Overall the application process is well defined yet uncomplicated enough so that it can be dealt with at the local level and with a minimum of turnaround time. This is important because of the relatively narrow window of opportunity that exists for the proper application of the material to road surfaces, usually late May to late June. Enforcement therefore, is highly reliant on this application process and the clear understanding of operators and regulators for what is require.

In the very rare case of non-compliance, the penalties for not fully meeting the requirements may seem mild to more litigative minded individuals yet it proves to be very effective nonetheless. Prosecutions through the court system have never been a truly effective alternative used by the ERCB in its enforcement programs. Instead the Board has chosen to follow other punitive measures for which it has a greater control. As an enforcement and regulatory body, the ERCB's main advantage through its statutes is to also be the licensing and approval agency within that industry. A much greater threat to a delinquent corporation would be the suspension of operations at the offending facility. Resumption of activity and production would only take place once specific criteria outlined by the ERCB were met. This may involve remedial measures such as new equipment and or detailed procedures for conducting certain practices. Inefficient time consuming legal battles with uncertain results take a tremendous toll on the resources and moral of staff, consequently it is our opinion that our enforcement process is more effective.

CHANGING POLICY AND ENFORCEMENT PROGRAMS

When problems or shortcomings do occur with a particular enforcement program, as it has in this case, it is not so much due to non-compliance by any particular operator but more through deficiencies or restrictions which exist within the policy itself. In our Informational letter IL85-16 two of these were eventually brought to the ERCB's attention by public interest groups no less. One concern was the method in which the oily waste was being applied to road surfaces and the other had to do with the use of this material for private country residential purposes. This presented quite a contradiction and paradox as on one hand there was a sector of the public concerned with the way this material was being put on roads and any potential adverse environmental effects while another group was lobbying very hard to get access to it for their own private use. The group objecting to the widespread use of this material on secondary roads reacted because of improper practices in an isolated area.

Normally, there would have only been a single application of oily waste material to a stretch of road in the same year, however in some areas repeated applications were being put on the same road within the same year and very often over consecutive years. This heavy road application would repeatedly cover up low spots in the road with quite a thick layer of the oily waste which tended to rut quite badly from heavy truck traffic. The oily waste material, unless very careful preparation steps are taken, does not have the type of consistency which gives it a good durable quality as a paving material. Local landowners therefore driving up and down these municipal roads find these ruts particularly dangerous and damaging to their vehicles. The generalized nature of our

characterization for the waste, approving it for road disposal as specified in the Informational Letter IL85-16, did not take into consideration repeated applications of waste over the same area. Damage to the local ecosystem in these instances could then be a very real possibility with this unexpected increase in the leachable elements of the waste.

In the other situation the Informational Letter states very clearly that private driveways and parking areas will not be allowed as disposal areas for the oily waste materials. Therefore, when private landowners requested their local government to undertake some form of dust suppression on the municipal roads in front of their homes, it was often done with this oily waste material donated by a local oil company. Some individuals saw this as a real benefit, and wondered if they could surface their private lanes from the municipal road to their homes and outer buildings. They could not understand the logic in why the ERCB would deny these requests when its saw fit to approve the material to go on the municipal road immediately in front of their homes. It soon became clear to the public, local authorities, heavy oil operators, and the ERCB that some refinement of the policy outlined by IL85-16 was required. The first step therefore, was to survey local government authorities and the various private interest groups for what they felt would be reasonable, the ERCB then struck a task force to look at rewriting the informational letter and updating it to the concerns outlined by the interested parties. The task force was eventually made up of key industry personnel specializing in environmental matters, other government of Alberta departments with expertise in this area such as Environment and Transportation, as well as highly respected representation from the scientific community and of course a number of appropriate senior ERCB staff. The overall objective was to cover two main areas, the first being of proper characterization of the waste so that if an analysis showed the material met the analytical criteria this would mean it would be sufficiently safe and benign so that it might be used in any road application situation whether it were local government or private. The second point was to develop guidelines in appropriate methods and frequency of surfacing roads with this material and to also deal with the issue of liability for the waste during and after its disposal to the road surface.

All of the data that had been collected from earlier years of disposal following the original guidelines set in informational letter IL85-16 was felt to be unusable by the scientific sector of the task force because of the inconsistencies in sampling and analyses methodology which took place in the past. The first recommendation was to develop a single appropriate protocol for sampling and analysis to be used by all operators so that consistent and meaningful data could be generated to indicate what were the predominant components found in the oily waste. In

developing the analytical protocol it was felt that before ruling out the need to look for certain elements, it was necessary to know if they were even present, at least in large enough concentrations to be of concern. The decision was to cover areas related to the physical parameters, inorganics and organics (Fig. 3). The ERCB then took on the responsibility for contacting all operators in the heavy oil sector and informing them of this protocol requirement and explain why this was required. The next step was to gather existing road surfacing techniques being used by operators around the area as well as good engineering practices endorsed by Alberta Transportation and tabulate these, assess them, and develop one preferred method. This method would then be discussed with the local municipal governments who were active in using this material on the roads as well as the majority of operators in the heavy oil area, note their comments and suggestions and then finalize the technique. The operating companies felt that liability regarding the waste would always lie with them and therefore, as a condition of approval for disposal, the operator must supervise the road surfacing program. In this way conformity to the preferred technique would be assured if for some reason the local government or contractor wanted to deviate from the program.

This entire exercise, in which participation came from a wide variety of responsible and concerned parties will result in a new informational letter which must include an effective set of guidelines with responsibilities and requirements clearly defined. The application and approval process will provide enough checks and balances along with the open willingness of industry for compliance with the policy. Any problems which may develop will more than likely be the result of a change in perception by any of the interested parties or new data regarding this process. For now the public's needs and concerns will have been met, local governments can still realize considerable savings to their own maintenance programs, industry's very real need to responsibly handle their wastes met and the ERCB will have a practical and almost self administering enforcement program in place.

Gravity of Heavy Oil	22.2° API or greater
Number of operating companies	13
Percentage of total Heavy Oil production	90 - 95%
Number of wells with tanks	2 100
Number of wells with flowlines	1 400
Number of batteries with treaters	63
Sand production from wells with tanks	55 000 yd^3/yr.
Sand production from wells with flowlines	20 000 yd^3/yr.
Average sand production per well	21 yd^3/yr.

FIGURE 1
SAND PRODUCTION IN HEAVY OIL OPERATIONS

(a) The waste must not contain significant amounts of free salt water, fracturing acids, or other non-hydrocarbon contaminants, halogenated hydrocarbon, or other manufactured oils.

(b) The oil in the oily waste must be of relatively high density.

(c) An analysis for free water content and chlorides is required

(d) Hazardous chemicals and the volumes injected during production must be identified.

(e) An estimated total volume to be disposed of and location of disposal must be provided.

FIGURE 2
DUST SUPPRESSION CHARACTERIZATION

1. Bulk density of the sample
2. Composition - percentages of oil, solids and water will be conducted on the whole sample.
3. Specific gravity of the oil phase is required.

4a. Flashpoint

4b. Viscosity of the oil phase.

5. Total Chlorides, mg/l, in the sample phase and extract from solid phase required. SAR (Ca, Na, Mg) and E.C. also required.
   Free water phase must not be present for total chlorides determination.
6. pH.
7. Total heavy metal content:
   - Boron - Chromium - Lead - Nickel
   - Cadmium - Mercury - Manganese - Vanadium
8. Leachable heavy metals (mg/l):
   - Boron - Chromium - Lead - Nickel
   - Cadmium - Mercury - Manganese - Vanadium
9. Leachable Phenols:
   The committee agreed to analyze during the summer testing program on a representative number of wells to assess whether phenol determination is required in the final guidelines.
10. Organic solvents:
   - Benzene - Ethylbenzene
   - Toluene - Xylene
11. Chlorinated Organic Screen Test:
   This will be qualified similarly to Leachable Phenols.
12. Aromatic Hydrocarbons:
   - Acenaphthene - Anthracene - Benzo (a) pyrene
   - Acenaphthylene - Benzo (a) anthracene - Benzo (b) fluoranthene
   - Benzo (ghi) perylene - Chrysene - Fluorene
   - Benzo (k) fluoranthene - Fluoranthene - Naphthalene
   - Phenanthrene - Indeno (1,2,3-cd) pyrene - Pyrene
   - Dibenzo (a,h) anthracene

FIGURE 3
NEW ANALYTICAL REQUIREMENTS

PRS TREATMENT AND REUSE OF OILFIELD WASTEWATERS

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Abstract

PREFERRED REDUCTION SERVICES, INC. (PRS) used a three phase program to develop and demonstrate an economical alternative for treatment and reuse of oilfield wastewaters. Scrubber blowdown, produced waters from steam flooding, and non-dispersed water-based drilling muds were used in the program. Identical physical/chemical treatment equipment was used for each waste, however, each waste required a different treatment scheme. Each treatment scheme resulted in environmentally acceptable liquid and solid products suitable for reuse.

Phase I sampled and characterized the wastewaters resulting from production and exploration activities. Phase II involved bench-scale treatment testing for the samples collected. The results provided data predicting the expected efficiency of full-scale demonstrations. Phase III field tested full-scale physical/chemical treatment equipment. Average removal efficiencies for total suspended solids, chemical oxygen demand, and oil & grease were greater than 95 percent. Operating costs and water reuse options were also determined.

Treated scrubber blowdown was of suitable quality to be reused as an oxygen scavenger. Treated produced waters were suitable for reuse in boiler feedwater pretreatment. Treated drilling muds were suitable for reuse in drilling operations. The solid residues produced were suitable for reuse in cement block and asphalt manufacturing.

The demonstration conducted by PRS showed that treatment and reuse options can be both viable and economically beneficial.

Background

Historically, drilling fluids, produced waters and other wastes associated with crude oil or natural gas production have been exempted from Federal and State Regulation. Management of these wastes have occurred in surface impoundments and underground injection wells. Due to the nature and quantity of these wastes, and growing environmental concerns, impoundment and injection are becoming less attractive.

Since 1982, all crude fired steam generators in Kern county, existing and new, were required to have scrubbers to reduce air emissions. Wet sulfur dioxide scrubbers are predominantly used as air pollution control devices.

During use scrubber waters are contaminated by constituents in the gas stream. Oilfield scrubber wastewater consists of sodium sulfite, sodium bisulfite and sodium sulfate. The pH of the scrubber water will vary depending on the type of scrubber used. Contaminated scrubber water is typically shipped off-site for disposal, or treated to remove fly ash and deep well injected.

Secondary oil recovery is very common in Kern County, California and in other heavy oil producing areas of the United States. In secondary oil recovery, water is pretreated, fed to a boiler, superheated and dispersed to well heads via feeder lines. From the well head the steam is injected into a formation to loosen crude deposits. The steam and loosened crude are brought to the surface where the oil is skimmed and refined. The byproduct of this activity is wastewater, referred to as produced water. This produced water is contaminated with oil, minerals and other natural substances.

Drilling mud is circulated through a well bore during drilling to remove cuttings from down-hole and to lubricate and cool the drill pipe and bit. During drilling a portion of the mud is rejected and jetted out into a reserve pit. Reserve pit drilling muds vary in salt, metal and oil concentration. High concentrations of salt and metals in the pits can complicate and limit closure options.

PRS designs, builds, manages and operates specialized central use facilities. PRS also provides either mobile or fixed treatment capability. To expand the applications of mobile units, PRS conducted a three phase program on the treatment of production wastewaters. The goals of the program were to:

1. Characterize samples of oilfield wastewaters,

2. Develop a treatment scheme for each waste,
3. Evaluate full scale treatment equipment and schemes,
4. Investigate reuse options, and
5. Determine if treatment and reuse are economically viable.

Among the mobile equipment available, a packaged in-line physical-chemical (PC) unit and a 1-meter belt press were chosen for consideration in the demonstration program. The PC unit was selected due to inherent flexibility and reliable treatment efficacy. The mobile belt press is considered a useful tool for dewatering of high solid content sludges. The PC unit has also been used in combinations with the belt press for secondary treatment of filtrate and backwash water, resulting from press dewatering.

Process Description

PRS's Physical-Chemical technology, PC, is proven on a full-scale basis for the treatment of waste streams generated by the metal finishing, electrical and electronic, paint formulation, battery manufacturing and timber production industries. The PC system is capable of performing any of the following processes:

pH Control	Neutralization
Skimming	Emulsion Breaking
Detoxification	Adsorption
Chemical Fixation	Coagulation
Flocculation	Filtration
Precipitation/Co-Precipitation	
Chemical Oxidation and Reduction	

The PRS PC systems typically reduce the volume of waste by 95%. The products of the treatment process are treated liquid effluent and solid cake. The effluent is of suitable quality for further treatment and reuse or discharge under Federal pretreatment requirements. The solid cake can either be recycled, reduced in toxicity, rendered nonhazardous, landfilled or incinerated. A summary of tests conducted to validate the processing capabilities are available from PRS.

The PRS PC systems are designed to achieve tertiary treatment in one step, while producing manageable sidestreams. Substantial removals, > 99%, are thus economically achieved by employing this technology.

Briefly, the PC systems use chemical and physical means to separate and concentrate contaminants in a waste. A complete cycling of influent is typically done in less than 45 minutes, and sometimes as low as 5 or 10 minutes. This process maintains

certain chemical process patents. Controls and filtration techniques are of proprietary nature.

Additional characteristics of the PC systems are; 1) the materials of construction provide for ideal corrosion protection; 2) the system allows for "add-on" chemical addition systems; 3) the control system is designed to provide feed-back or feed-forward control of chemical addition; 4) the control monitors adjust the addition rate of chemicals; 5) the microprocessor controls allow for fail-safe, unattended operation; and 6) the system operates on a demand basis which conserves power for intermittent wastestreams.

Wastewater Characteristics

In Phase I the wastes were characterized and bench test parameters were determined. A literature review and sampling was conducted. Samples were collected from oil fields in Kern County, California. Generally, the chemical characteristics of concern for scrubber wastewater are pH, toxic metals, total suspended solids (TSS) and total dissolved solids (TDS).

Produced waters are generally contaminated by conventional pollutants. Specifically, Chemical Oxygen Demand (COD), Total Suspended Solids (TSS), Oil & Grease (O&G) and trace metals.

Drilling fluids are contaminated with high TSS, high TDS and salt, drilling lubricant additives, COD, metals and trace organics.

Tables 1, 2 and 3 show expected characteristics of scrubber blowdown, produced water and drilling mud.

Table 1
Scrubber Blowdown

Constituent	mg/l	Constituent	mg/l
Boron, B	35.0	Vanadium, V	31.0
Chloride, Cl	2130.0	Zinc, Zn	0.20
Calcium, Ca	31.0	Silica, SiO_2	150.0
Copper, Cu	0.49	Sulfite, SO_3	32500.0
Chromium, Cr	0.16	Sulfate, SO_4	67.0
Iron, Fe	95.0	Bicarbonate, HCO_3	2324.0
Potassium, K	42.0	Carbonate, CO_3	0.0
Magnesium, Mg	29.0	Hydroxide	0.0
Nickel, Ni	0.29	Calcium Carbonate	367.0
Sodium, Na	2060.0	Sodium Chloride, NaCl	4953.0
Sulfur, S	0.0		
pH	6.89	TDS	5950.0
Conductivity	9270 µmho/cm	TSS	540.0

Table 2
Drilling Mud

Constituent	mg/l	Constituent	mg/l
Arsenic, As	2.0	pH	8.3
Barium, Ba	45.0	% Solids	19.25
Cadmium, Cd	0.58	TSS	540.0
Chloride, Cl	530.0	Specific Gravity	1.004
Copper, Cu	11.0	C.O.D.	550.0
Chromium, Cr	10.0	Conductivity	3335 µmho/cm
Iron, Fe	100.4		
Lead, Pb	15.0		µg/kg
Nickel, Ni	12.0	Benzene	15
Vanadium, V	18.0	Ethyl Benzene	23
Zinc, Zn	47.0	Toluene	91
		Xylenes	240

Figure 3
Produced Water

Constituent	mg/l
pH	8.3
Conductivity	3335.0
Chloride, Cl	530.0
C.O.D.	550.0

Bench-Scale Testing

Phase II bench-scale treatment investigations were conducted on samples collected. The purpose of bench-testing was to determine the proper treatment scheme for each waste. These schemes would be used in the full-scale demonstration. Cost estimates were also prepared to estimate the economic viability of treatment.

Coagulants, flocculants, polymers, metal precipitation and rotary vacuum filtration were used in the treatment. Precoat filtration was used for scrubber blowdown and produced water. Conventional rotary vac and belt press dewatering were used for non dispersed drilling muds. The results of bench testing are detailed in Figures 5, 6 and 7.

Scrubber samples used for bench scale testing were supplied to PRS by the generators. The generator verified them as representative. Treatment consisted of temperature adjustment, coagulation, flocculation and precoat filtration. Precoat filtration was simulated on PRS's bench scale treatment system (.4 square feet of filter area). This precoat filter results in submicron removal of particulates. The treatment resulted in > 99 % removal of total suspended solids. The treatment did not result in any sidestreams which required further treatment. The

filter cake had a solids content of > 65 % (dry weight) and was easily manageable.

Table 4
Bench Scale Results on Scrubber Blowdown

Parameter	Influent	Effluent	Filter Cake	% Removal
Arsenic, As	ND<0.001	-	ND<0.001	-
Barium, Ba	ND<0.1	-	ND<0.1	-
Cadmium, Cd	ND<0.005	-	ND<0.005	-
Chromium, total	ND<0.05	-	7.99	-
Copper, Cu	0.11	<0.08	ND<0.02	27.27
Iron, Fe	7.0	<0.34	8493.0	95.14
Lead, Pb	ND<0.1	-	ND<0.1	-
Mercury, Hg	ND<0.2	-	ND<0.2	-
Nickel, Ni	ND<0.04	-	ND<0.04	-
Zinc, Zn	ND<0.005	-	230.30	-
Sulfide	ND<1.00	-		-
Chloride, Cl		100.0		
Sulfate, SO_4		<10000.0		
Sulfite, SO_3		<35000.0		
TSS		<10.0		
pH	6-9	6-9		

All units are ppm.

For drilling mud, bench test samples were obtained from three randomly selected reserve pits. All but one of the samples were water based, and non-dispersed. Treatment studies involved flocculation jar tests and mechanical dewatering by different techniques. The mud and water phases were treated together.

It was determined that at high solids content (>15%), flocculation of particles was difficult. The most effective polymers tested were nonionic and moderately charged anionic types. One sample required significant amounts of flocculant to overcome the effects of dispersants. The separation achieved, however, was very fragile.

A filter leaf with a septum of 5 micron retention was determined to be the most effective in dewatering studies. Dewatering of polymer treated muds resulted in solids capture > 99%. The resulting cake was 35 % solids by dry weight. Through the use of additional body-fed filter-aids, cake solids content increased to 48 %. The filter-aids also increased dewatering rates, prevented blinding of the septum and provided solidification/stabilization of metals.

Table 5
Bench Scale Results on Drilling Muds

Parameter	Influent	Effluent	Filter Cake	Effluent % Removal
Arsenic, As	ND<0.001	-	ND<0.001	-
Barium, Ba	ND<0.1	-	5.20	-
Cadmium, Cd	ND<0.005	-	ND<0.005	-
Chromium, total	0.19	ND<0.05	50.30	73.68
Copper, Cu	0.11	0.04	24.40	63.64
Iron, Fe	100.4	<0.03	415.5	99.97
Lead, Pb	ND<0.1	-	ND<0.1	-
Mercury, Hg	ND<0.2	-	ND<0.2	-
Nickel, Ni	0.13	ND<0.04	24.30	69.23
Zinc, Zn	4.22	0.38	85.90	91.00
Benzene (µg/l)	11.55	ND	ND	99 +
Toluene (µg/l)	12.47	ND	ND	99 +
Ethyl Benzene (µg/l)	31.90	ND	ND	99 +
Xylene (µg/l)	6.73	ND	ND	99 +
O & G		<10		
COD		<150		
Conductivity		<800 µmho/cm		
Chloride, Cl		<1000		
TSS		<10		
Total Solids	19.25%	0.16%		99.17
pH	8.72	7.0		

All units in ppm unless otherwise indicated.
ND = not detected

For produced waters, samples were taken and verified as representative by oilfield personnel. The samples were labelled as produced water and multimedia filter backwash water resulting from the treatment of production waters. The treatment scheme used was identical to that used for scrubber waters, but included pH control and a different coagulant. This coagulant also exhibited oxidization properties.

The treatment consisted of pH adjustment, coagulation, flocculation and precoat filtration. The same filtration media was used as with scrubber waters; 1 micron retention septum with 2 inch precoat. The influent samples were relatively free of arsenic, barium, cadmium and chromium, therefore removal effectiveness could not be determined. It is predicted that the removal of these metals will be greater than that achieved for scrubber water since pH was controlled. The PC-M30 has consistently shown 99+ % removal for these metals in dilute wastewater.

The treatment did not produce any sidestreams which required further treatment. The filter cake was > 40 % solids (dry

weight). The filtrate was suitable for return as boiler feedwater.

Table 6
Bench Scale Results on Produced Waters

Parameter	Influent	Effluent	% Removal
Arsenic, As	ND<0.001	ND<0.001	-
Barium, Ba	ND<0.1	ND<0.1	-
Cadmium, Cd	ND<0.005	ND<0.005	-
Chromium, total	ND<0.05	ND<0.05	-
Copper, Cu	0.49	ND<0.02	95.92
Iron Fe	0.33	<0.03	90.91
Lead, Pb	ND<0.1	ND<0.1	-
Mercury, Hg	ND<0.2	ND<0.2	-
Nickel, Ni	0.49	ND<0.04	91.84
Zinc, Zn	0.20	0.26	0
COD	550.0	175.0	68.18
Conductivity	3335.0	2500.0	25.04
Chloride, Cl	530.0	230.0	56.60
TSS		7.0	
TDS		1343.0	

All units in ppm unless otherwise indicated.

FIGURE 1

PC-M30 TREATMENT FLOW DIAGRAM

OILFIELD WASTES

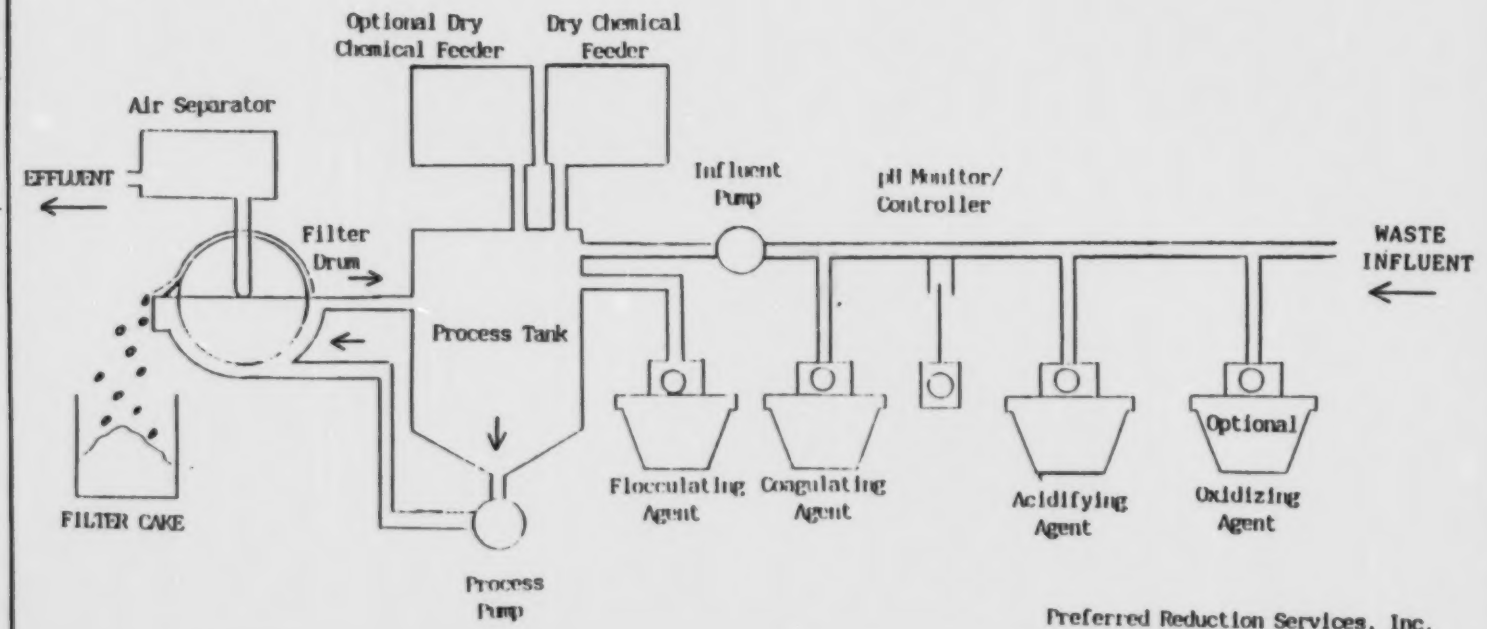
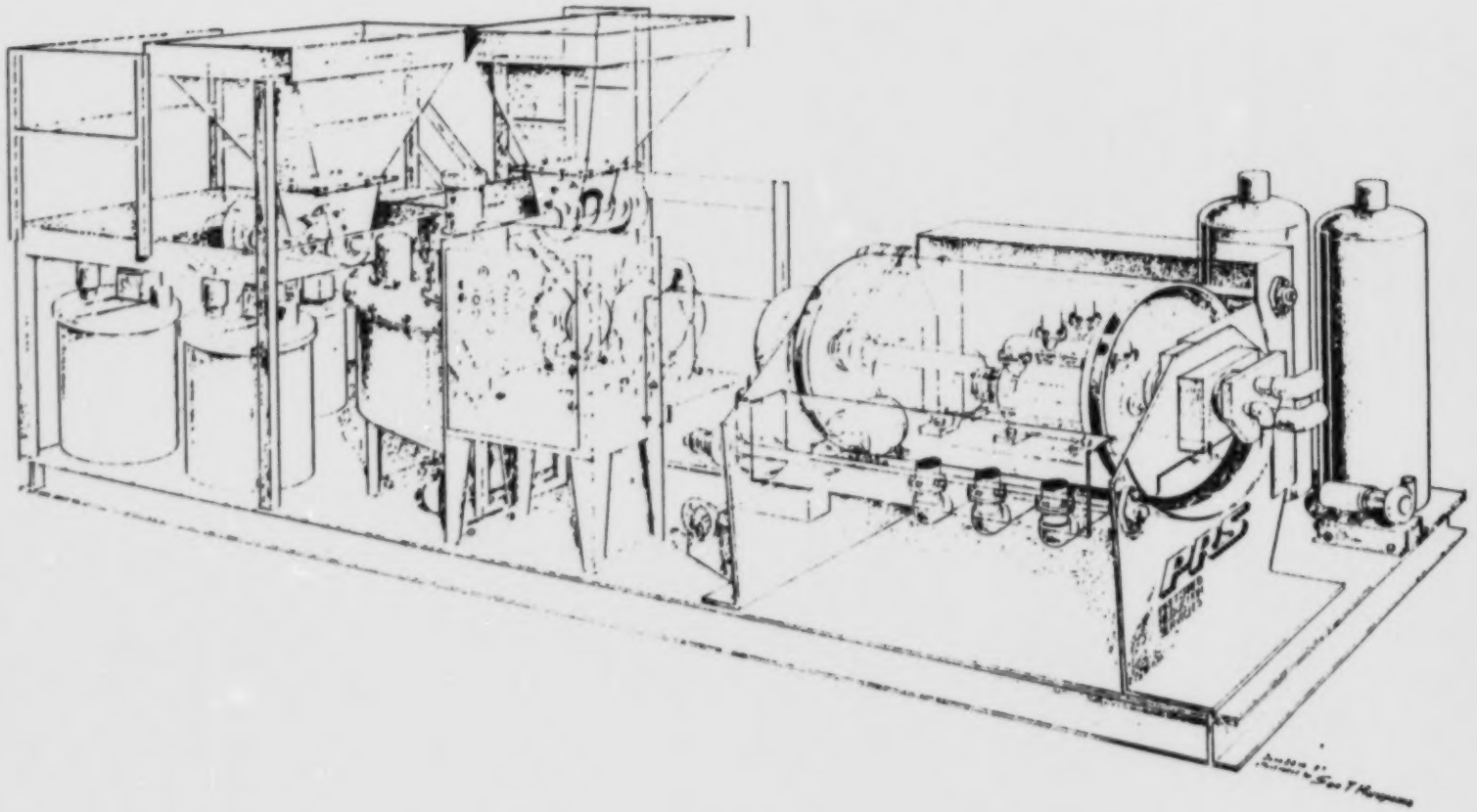


FIGURE 2

PRS PHYISCAL/CHEMICAL TREATMENT UNIT

(PC-M30)



Field Demonstration

Phase III field tested the bench-scale treatment schemes. The full scale demonstration was conducted in Kern County, California by PRS. The PRS PC-M30 (Physical Chemical Treatment unit) was transported to the oilfield on a single semitrailer. Setting up the demonstration equipment involved hookup to waste and power supply.

The demonstration was conducted on scrubber blowdown and produced waters only. Permission to treat drilling muds onsite could not be obtained from the generator in time to be included in the demonstration. The generator also retained the demonstration data on the produced water.

The demonstration was conducted over a three day period. In that time, 6500 gallons of scrubber blowdown and 15000 gallons of produced water were treated. As a result of bench scale work, minimal optimization was required. The PC-M30 proved to be quite adaptable to each of the different streams tested.

Table 7
Field Treatment of Scrubber Blowdown

Parameter	Influent	Effluent	Filter Cake	% Removal
Chromium, tot	0.16	0.08	48.70	50.00
Copper, Cu	0.18	0.04	9.73	77.78
Iron, Fe	7.56	0.34	2063.0	95.50
Nickel, Ni	8.84	0.65	1739.0	92.65
Vanadium, V	36.75	2.45	1635.0	93.33
pH	6.8	6.6		
TSS	15400	3.0		99.98
Total Solids			68.0%	

* All units are in ppm.

The scrubber blowdown generator's only objective was to evaluate the degree of suspended solids removal and filter cake moisture. As a result, no attempts were made to remove soluble metals. In the demonstration higher removal efficiencies were achieved for copper and iron than in bench tests.

The treated scrubber water was suitable for return use in boiler feedwater pretreatment.

Due the organics contained in produced water and drilling muds, carbon adsorption is recommended for future installation.

Conclusions and Results

PREFERRED REDUCTION SERVICES, INC. proved that the treatment of scrubber water, produced water and drilling mud was not only feasible, but economical.

The residual sodium sulfite from treated scrubber blowdown can be effectively reused as an oxygen scavenger in boiler feed waters. The treated scrubber effluent can contain between 2.3-5.5% sodium sulfite and sodium bisulfite. In using the treated scrubber effluent as an oxygen scavenger cost savings are realized from reduced sodium sulfite purchases and steam generator feedwater quality is improved.

The drilling mud and produced water effluents were of good quality for reapplication in field operations. With further treatment these waters, primarily for salts, could be made suitable for irrigation and potable uses.

Treating these oilfield wastes provides several benefits:

1) Environmental liability associated with land application, impoundment, and underground injection is minimized,
2) Potential migration from impoundment and injection is minimized,
3) The esthetics and public perception of oilfield activities can be increased by decreasing the use of impoundments,
4) Cost saving can be realized from reuse of the treated effluents.

Several options exist for management of treated water. Specifically, reuse in the production field, deep well injection, sewering, NPDES discharge, or use as irrigation with further treatment. Since many large fields are located in semi-arid climates, the potential benefits of water recycling are great.

The filter cakes generated were high in solids content, therefore required no further solidification prior to landfilling. The land disposal treatment standards may require the cakes to be treated by stabilization or metals recovery prior to land disposal.

An outlet discovered for the reuse of filter cake is in cinder block and asphalt manufacturing. In order to make the filter cake a viable substitute in either of these applications, considerable quantities are needed by the manufacturer. The quantities of wastewater produced in oilfield activities is sufficient to meet this need. Use of the filter cake as a substitute for raw materials is the preferred method of cake management. Management of this type eliminates disposal headaches for the generator and reduces costs for the manufacturer.

In conclusion, proper treatment of wastewaters resulting from oilfield activities are waste specific. Laboratory treatment diagnosis is required to establish monitoring criteria and to avoid potential problems when specifying treatment equipment. It is important to identify how interacting processes may affect one another when selecting a treatment train.

Proper planning can reduce reserve pit problems. Specifically, lubricating oil, trash, and completion work brines should not be placed in the reserve pit.

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A RAPID METHOD FOR THE DETERMINATION OF THE RADIUM CONTENT OF PETROLEUM PRODUCTION WASTES

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Abstract

A rapid assay method that can identify, with a high degree of assurance, if the Naturally Occurring Radioactive Materials (NORM) present is deminimis or if certain levels warrant concern, is essential to the successful and cost effective management of NORM wastes and NORM contaminated equipment. This paper addresses the measurement of radiation fields around equipment at the work site and demonstrates that under rigidly controlled conditions of sample geometry, it is possible to reliably estimate the specific activity of NORM material contained in sample bottles and in drums.

The results of field instrument assays for laboratory spiked materials containing 226 Radium, for laboratory samples generated by diluting assayed samples of scales and sludges and for an assemblage of 50 field samples of varying sample weights are presented. These results are compared with theoretical calculations and are found to be in good agreement. Similar results are presented for drum materials. Theoretical calculations made for tubing containing scale also appear consistent with field sample results reported for the United Kingdom and those performed in the United States.

Recommended sample correlations are presented for bottled samples, drums and tubing.

Introduction

The safe handling of production generated Naturally Occurring Radioactive Materials depends upon methods of identifying where such materials are found, quantifying the level of NORM present and having options available

to manage the materials in an environmentally safe manner. 226 Radium is easily found with hand held survey meters and the results of such surveys have been widely distributed by the American Petroleum Institute (API) and others. Experience with the management of Uranium mill tailings and phosphate fertilizer production waste, as well as studies in the petroleum industry suggest that there are a number of available management technologies that can be employed.

The main problem facing petroleum operators is the lack of proven sets of rapid methods for reliably and conservatively estimating the quantity of Radium present.

The State of Louisiana has partially addressed this issue in recent emergency regulations. It specified that any site where radiation exposure levels exceeded 50 uR/hr must be registered with the Department of Environmental Quality. It did not, except by implying that a radioactive assay be conducted, specify how to determine whether the Radium present was deminimis.

Radioactivity assays are expensive. (They cost between 50 to 150 dollars per sample depending upon the total numbers of samples submitted and the complexity of the assay.) The sample turn around time can be as long as ninety days. It would greatly improve operational efficiency and overall productivity if a simple screening method could be used to determine the need for a more elaborate analysis or to present a conservative estimate of content to expedite waste management decisions.

It is the purpose of this paper to describe some simple methods for estimating the quantity of Radium present and to suggest measurement methods and correlations for field operator use.

Materials and Methods

The first problem that had to be resolved in the development of a rapid screening method was the identification of standard geometries to be used in making the measurement. Most of the equipment in the oil patch is non-standard in shape and size and is selected to meet field conditions. There are some fairly standard items such as production tubing, sucker rods, fifty-five gallon drums and sample bottles. The standard geometries identified as offering the best promise for the development of a screening method were production tubing, fifty-five gallon drums, and completely filled wide-mouthed, one-liter polyethylene sampling bottles (Fisher Scientific or equivalent).

The hand-held survey meters selected for use in this study are typical of those currently in use in the industry. The survey instruments used were the Ludlum Model 19 Micro R meter (one by one Sodium Iodide detector with a rate meter readout, sensitivity 180-200 cpm per uR/hr.) and the Ludlum

Model 97-3. The Ludlum 97-3 is a Model 19 that has been modified to accept an input from an external detector as well as its internally mounted scintillation detector.

The use of a portable scaler/single channel analyzer (Ludlum model 2221 using a Ludlum Model 4410 two by two Sodium Iodide detector) was also evaluated as a measurement tool.

The hand-held survey instruments used in this study were calibrated at Ludlum's Sweetwater, Texas facility using a 137 Cesium source to calibrate the zero to 5 mR/hr range and to determine the ratio of cpm per uR/hr. A pulse generator was used to calibrate the other ranges.

This calibration method was selected instead of comparison with a pressurized ionization chamber, because the manufacturers standard calibration was the one most likely to be consistently used by the field operators. The portable scaler was calibrated in accordance with he manufacturer's instructions.

It was decided to take measurements with the instrument placed at the following locations:

1. Resting at the center and in contact with the tops of filled drums;

2. With the most sensitive part of the instrument in contact with the center of the bottom and at the sides of filled sample bottles; and

3. Where possible, at the center lengthwise, of a piece of production tubing (joint).

Samples were also collected for gamma ray assay by Controls for Environmental Pollution (CEP) of Santa Fe, New Mexico in order to provide correlations between field measurements and the specific activity present in the vessel, sample bottle, or joint being examined. Each sample provided to CEP contained between 800 to 2100 gms of material (average 1383 gms plus or minus 83 gms). Measurements were also taken at the bottom and around the circumference along the vertical center line before sending the sample to CEP.

CEP was instructed to hold all samples until equilibrium with the Radon daughters was reached and to report the measured specific activities of 226 Radium, 228 Radium and daughter products. Sample weight was also reported.

In conjunction with the collection of field samples, standard samples consisting of Louisiana Chalk spiked with NBS traceable quantities of

Radium solution or actual assayed production scale and sludge samples diluted with New Mexico sand were prepared. The tare weight and the sample specific activity were recorded for each sample. Measurements were taken on these samples using the hand held survey instruments and the portable scaler with the window open and with the window centered over the .609 kEv photopeak of 214 Bismuth.

Theoretical correlations derived using simple computer programs were prepared and were compared with the results of field measurements. The correlations for the top of drum and bottom of sample bottle assumed a point detector and calculated the radiation from each one centimeter layer for a range of densities. Correlations derived for pipe and the side-on measurements of sample bottles assumed that all the material in the container was concentrated in a plane parallel to the surface of the detector and that a point detector was positioned one radius from the geometric center of the plane. Correlations were prepared for pipe which were two, two and one half, and three inches in inside diameter and with varying thicknesses of deposit and material densities.

Results

It was clearly evident, as demonstrated by Figure 1, that the total quantity of radium present correlated well with the readings of the hand held survey meters and the portable scaler. It appeared that small deviations in sample geometry, wide variations in sample size and differences in sample density did not effect the overall result.

The best correlations were noted for the case of bottled samples. Figure 2 shows the results of the field measurements normalized for density. Figure 3 shows the calculated response for the same samples. Figure 4 shows the results for the New Mexico and Louisiana spiked materials, while Figure 5 shows the agreement between the field and predicted results at the same density. Figure 6 shows the confidence interval for the fit of the regression line.

The results of measurements using spiked materials and the portable scaler are shown in Figure 7 and the results using the single channel analyzer mode are shown in Figure 8.

Theoretical and experimental correlations for drummed materials are shown in Figures 9 and 10.

Theoretical and experimental correlations for tubing are shown in Figures 11 and 12.

Conclusions

Material contained in full wide-mouth, one-liter sampling bottles can be assayed using hand-held survey meters, portable scalers or single channel analyzers with reasonable accuracy. The single channel analyzer appears to offer the highest degree of accuracy and sensitivity. The hand-held survey instrument is the least accurate and sensitive.

The hand-held survey meter was noted to be sufficiently sensitive to estimate specific activities in excess of 20 to 30 pCi/gm, with high assurance (in the order of 98%) that the quantity estimated will be greater than that found in the sample container.

The contents of drums can also be reliably estimated using a hand-held survey meter at levels of approximately 40 pCi/gm and above. Our data does not permit the estimation of a numerical confidence interval, but it should be at least as good as that of the sample bottles. This statement is supported, in part, by the similarity in the derivation of the theoretical response to drums and bottles. It is strengthened by the good agreement between theory and experiment shown in Figure 5.

It does not appear reasonable to place much reliability on the estimates made for tubing with hand held equipment shown in Figure 12 since only four experimental results were available for comparison. The results are presented for range finding purposes only.

Recommendations

It is recommended that the initial screening of field material contained in drums and filled one-liter polyethylene bottles with specific activities above approximately 25 pCi/gm be accomplished using the Ludlum Model 19 or the Ludlum Model 97-3 hand-held survey meter. This screen can be performed by trained field operators. The portable scaler in the single channel analyzer mode should be used to accurately determine lower levels of activity when necessary. The single channel analyzer method should only be performed by persons specially trained to perform the analysis. Survey instruments should not be used to estimate the specific activity of material contained in production tubing, without first collecting and placing the scale in a one-liter bottle.

The estimation of the level of Radium contained in waste drums and sample bottles includes the following steps.

1. Determining the background.
2. Checking the instrument's response.
3. Making the measurement.

4. Estimating the specific activity of Radium present.

The background level used in making the estimate of specific activity should be measured in a location well removed from sources of radiation. Background should be measured at waist height. Four readings should be taken with the instrument parallel with the cardinal points of the compass. The reference background level used in making the estimate should be the average of the four readings taken.

This average should be compared with other background determinations. If it is significantly different from other similar measurements (greater than plus or minus 25%) then the cause of deviation should be established.

Instrument response should be checked using the 137 Cesium check source purchased with the instrument. The check source should be placed against the most sensitive part of the instrument and the reading recorded. If this measurement is not within plus or minus 15% of those previously recorded then the cause of the deviation should be determined. It may be necessary to replace the batteries and/or recalibrate the instrument.

For the case of sample bottles, measurements should be taken with the detector as close to the bottom of the bottle as possible. Measurements should also be made with the bottle lying on it side. The detector should be held at the longitudal and vertical center of the bottles. The bottle should be rotated through 360 degrees and a measurement made every 90 degrees. The average of the five measurements should be used in estimating the specific activity of the sample. This average should be background corrected.

In the case of the drum, the drum should be removed from other sources of radiation that might interfere with the measurement. The hand-held survey meter should be placed with the detector directly over the center of the drum and in contact with the top. The reading should be background corrected.

Estimates of specific activity are then made using Figures 13 and 15 for bottles and Figure 14 for drums. The results should be reported as being less than the quantity shown on the appropriate chart in units of pCi/gm.

IMPACT, TOTAL AMOUNT OF RADIUM PRESENT
USING LUDLUM MODEL 19 OR MODEL 97-3
(1 X 1 SODIUM IODIDE DETECTOR)

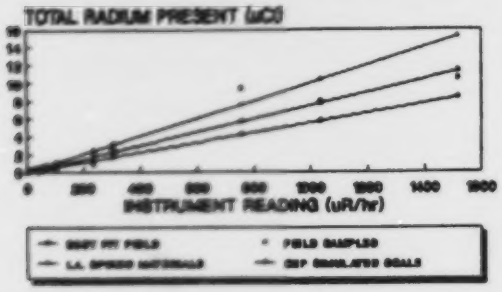

Figure One

SAMPLE BOTTLE CORRELATIONS
FIELD MEASUREMENTS NORMALIZED BY DENSITY
1000 ML WIDE MOUTHED POLYETHYLENE BOTTLE

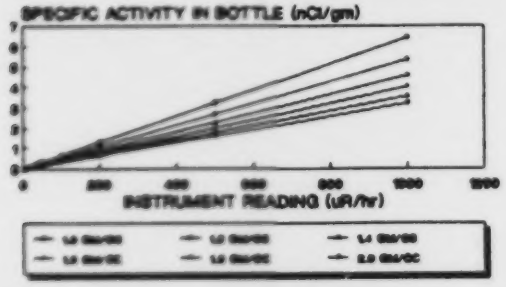

Figure Two

SAMPLE BOTTLE CORRELATIONS
THEORETICALLY DETERMINED BY DENSITY

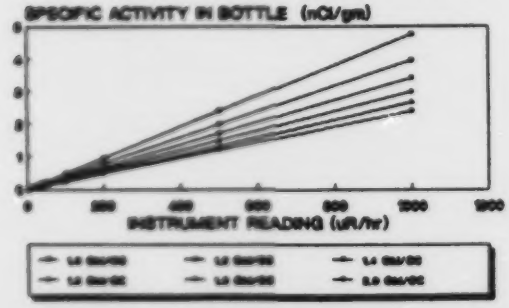

Figure Three

COMPARISON OF LOUISIANA (LA) AND
NEW MEXICO (NM) SPIKED SAMPLES

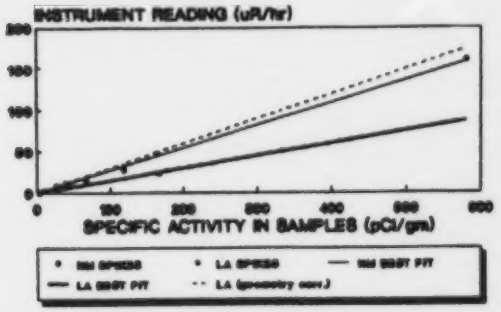

Figure Four

COMPARSION OF CORRELATIONS
THEORETICAL AND EXPERIMENTAL RESULTS
FOR SAMPLE BOTTLES WEIGHING 1300 GMS

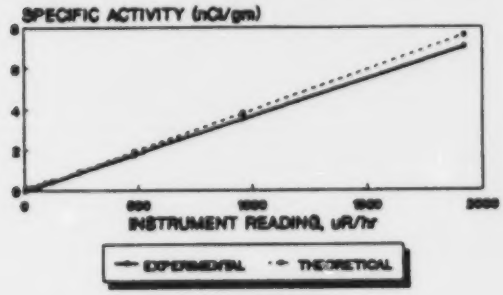

Figure Five

FIELD MEASUREMENT CORRELATIONS
ENVELOPE OF BEST FIT
SURVEY INSTRUMENT DATA

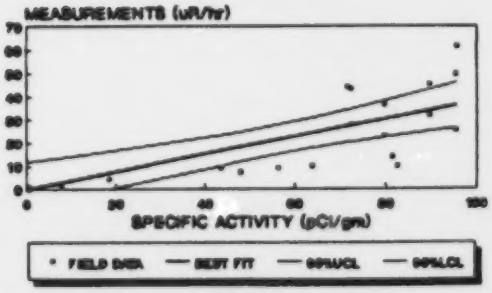

Figure Six

USE OF A SCALER TO
DETERMINE THE QUANTITY OF RADIUM

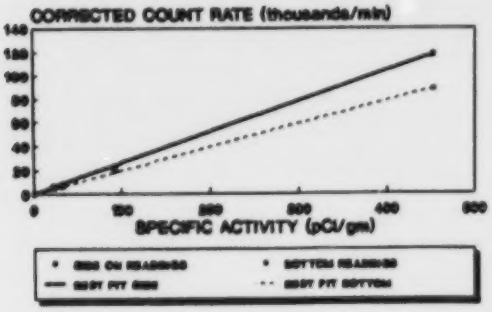

Figure Seven

USE OF A SINGLE CHANNEL ANALYZER TO
DETERMINE THE QUANTITY OF RADIUM

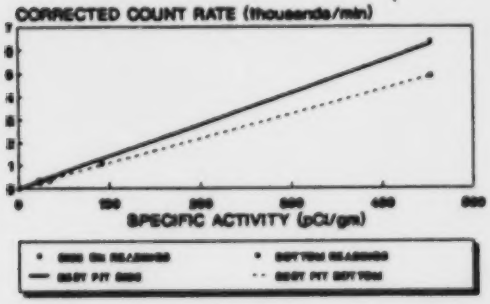

Figure Eight

CORRELATION FOR DRUMMED MATERIAL
EXPERIMENTALLY DETERMINED

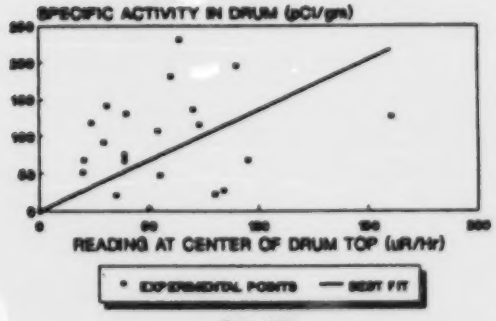

Figure Nine

THEORETICAL CORRELATIONS
FOR DRUMMED MATERIAL
NORMALIZED BY DENSITY

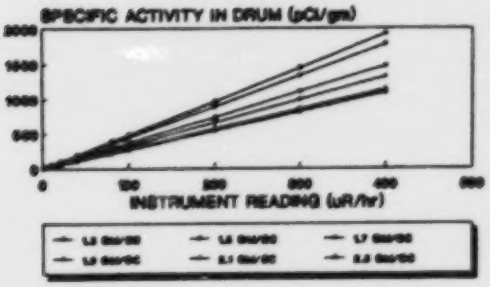

Figure Ten

THEORETICAL CORRELATIONS FOR PIPE
2, 2 and 1/2 and 3 inches I. D.
Scale Thickness 0.0125 inches

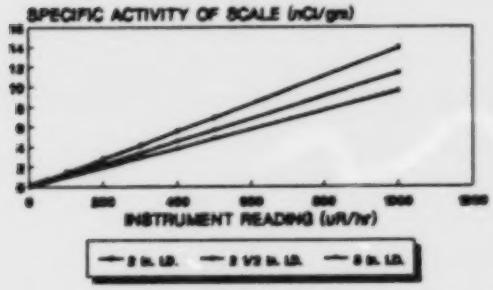

Figure Eleven

EXPERIMENTALLY DETERMINED FOR
CORRELATION OF INSTRUMENT READING
AND SCALE IN PIPE (NO ID STATED)

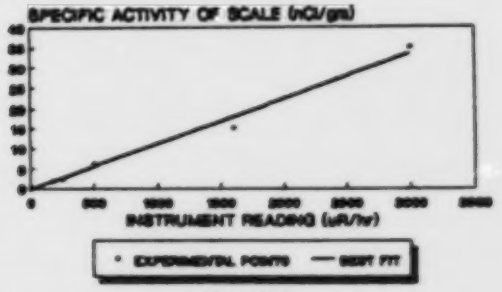

Figure Twelve

RECOMMENDED CORRELATIONS
FOR SAMPLE BOTTLES

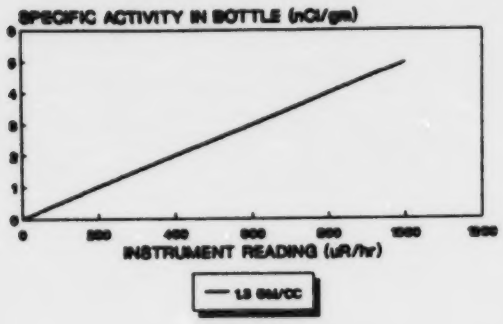

Figure Thirteen

RECOMMENDED CORRELATION
DRUMMED MATERIAL

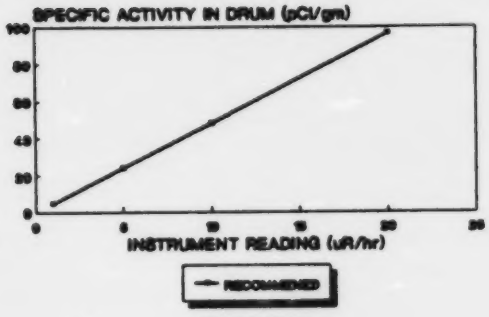

Figure Fourteen

RECOMMENDED CORRELATIONS
FOR SAMPLE BOTTLES
97.5 % of results will exceed actual

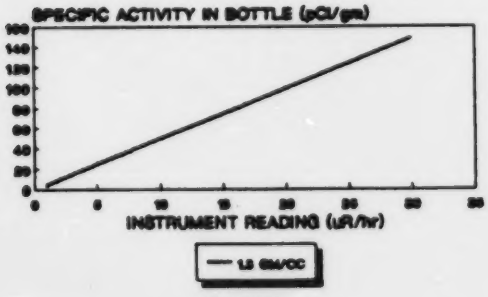

Figure Fifteen

A REGULATORY HISTORY OF COMMERCIAL OILFIELD WASTE DISPOSAL IN THE STATE OF LOUISIANA

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Introduction

During the late 1970's and early 1980's emotions in the Louisiana oil patch were running high on both sides of the arena. Oil and gas interests were experiencing a boom of sorts as the number of drilling permits issued by the Louisiana Department of Natural Resources, Office of Conservation rose from 3707 in 1977 to a high of 7631 in 1984. Concerned citizens were awakening to the possibility that current oilfield waste disposal practices were polluting the soil and groundwater and fouling the air. Nationally, the Environmental Protection Agency (EPA) had proposed to regulate certain categories of oilfield waste as "special wastes" in the hazardous waste regulations of December 8, 1978 (43 FR 58946). Oil and gas industry lobbying efforts resulted in the Resource Conservation and Recovery (RCRA) amendments of 1980 which exempted most oil and gas wastes from the hazardous waste requirements of Subtitle C until the outcome of further study by EPA.

Back in Louisiana, the Vermilion Association for the Protection of the Environment (VAPE) was moving forward under the leadership of Mrs. Gay Hanks and Mr. Lloyd Campisi to stop the construction and operation of a growing number of commercially operated and non-regulated oilfield disposal pits in Vermilion Parish. This close-knit rural community in south central Louisiana was concerned about the types of waste being dumped at these sites and the truck traffic at all hours of the night. Therefore, at the request of his constituents, Representative Sammy Theriot of Lafayette, Louisiana, drafted and sponsored House Bill No. 481 during the 1980 Louisiana legislative session.

Passed as Act No. 804 in August of 1980 the new law amended Section 4 of Title 30 of the Louisiana Revised Statutes of 1950. Title 30, Section 4(I) then required the Commissioner of the Office of Conservation to promulgate rules, regulations, and orders as necessary "to control the offsite disposal at commercial facilities of drilling mud, salt water and other related nonhazardous wastes generated by the drilling and production of oil and gas wells". The rules were to provide for a new and complete regulatory program for the permitting, siting, design, operation and

closure of commercial offsite disposal facilities.

Initial Rule Promulgation

In July 1980, one month prior to passage of Act 804, the Office of Conservation published a revision of existing oil and gas regulations, Statewide Order No. 29-B: the first attempt to regulate commercial oilfield waste disposal operations in Louisiana. Section XV, Paragraph 13 of 29-B defined a "commercial facility" as "a waste treatment, storage or disposal facility which receives, treats, reclaims, stores or disposes of waste drilling muds or salt water for a fee or other consideration". The new rule identified oilfield waste as oil base and water base drilling muds and cuttings and salt water (produced brine) and provided guidelines for construction and operation of earthen pits. Most notable aspects of the rule are as follows (1):

1. Pits were not to be located in a flood zone according to federal guidelines and flood insurance maps.

2. Documentation was required to show that an impermeable clay barrier existed below the pit.

3. At least one monitor well had to be installed down gradient.

4. Disposal operations could be conducted during daylight hours only.

5. A manifest system was implemented to document waste shipments.

6. Facilities were required to submit funding to provide for adequate closure.

7. Financial responsibility (bonding/insurance) was to be provided for any liability for damages which might be caused by the escape or discharge of any waste from the disposal facility.

Existing facilities were granted interim permits and required to comply with the new rule within 90 days of passage. A field and file search resulted in the discovery of thirty-one existing sites. Sixteen operated closed systems with above-ground storage tanks and saltwater disposal wells. Fifteen sites utilized earthen pits for storage/disposal of drilling muds, cuttings and salt water. Interim permits were converted to final permits when existing facilities complied with the applicable requirements of Paragraph 13. Only eighteen facilities ever received final approval to continue operating. Of these, thirteen are still in existence. Thirteen facilities lost interim permits and discontinued operations. Although a few sites were cleaned up and pits closed, several others have never been properly closed. At least two sites in Vermilion Parish eventually became EPA superfund sites.

1983 Amendments

The 1980 commercial facility regulations were not perfect, but they formed a firm foundation upon which to build. Except for a 1982 amendment of 29-B dealing with injection (saltwater disposal) wells in conjunction with EPA approval of the Louisiana Underground Injection Control (UIC) program, the commercial facility regulations were not changed until 1983. Citizen groups in various Louisiana parishes were demanding that strict location and design criteria be added to the requirements for commercial oilfield waste sites. Review of monitor well data indicated that saltwater storage pits were leaking into shallow water-bearing strata; such pits were condemned. Drilling fluid pits were filling up and more were being constructed. Housekeeping practices at existing facilities were not protective of the environment. A new means of treating waste was needed, since pits appeared to be a less desirable disposal option. Therefore, Paragraph 13 was amended extensively in 1983 to take these facts into consideration. The following is a summary of the major aspects of the 1983 amendments (2):

1. Facilities utilizing pits for storage of oilfield waste solids were required to submit and have approved a plan of disposal of pit solids prior to July 1, 1984. In effect, these sites were told that disposal (storage) of waste in pits was a practice that was no longer acceptable. New treatment and disposal technologies were encouraged. It is interesting to note that this requirement was located in a new section outlining criteria for operation of land treatment (landfarm) systems. Such criteria included the following:

   (1) Soil type and permeability requirements for treatment cells;

   (2) pH was to be maintained at 6.5;

   (3) If necessary, underdrain systems were to be installed in cells to maintain the water table at least 36 inches below the zone of waste incorporation to maintain aerobic soil conditions in the treatment zone;

   (4) The electrical conductivity (EC) of the treated waste could not exceed 10 mmhos/cm;

   (5) The sodium adsorption ratio (SAR) of the treated waste could not exceed 10;

   (6) Organics (oil and grease) had to be kept to a minimum in order to maintain plant growth (no limit provided);

   (7) An unsaturated zone monitoring system was required; and

   (8) An independent consultant was required to perform necessary monitoring.

Primarily, these criteria were derived from standards applicable to agricultural settings. The idea was to return the site to some form of beneficial land use at the end of the operational life of the facility.

2. New commercial facilities could not be located in certain areas, as indicated below:

   (1) Within 500 feet of a residential, commercial or public building unless a waiver was granted;

   (2) Where subsurface geology was not suitable for disposal of waste in a saltwater disposal well;

   (3) Pits could not be located in a flood zone unless levees were built at least one foot above the 100 year flood level; and

   (4) Where other conditions existed which in the determination of the Commissioner of Conservation would pose a threat of substantial, adverse effects on the environment.

3. Certain design criteria were added to prevent environmental impact from facility operations.

4. Each load of waste received by a commercial facility had to be tested for pH, conductivity, and chloride (Cl) content and an eight ounce sample maintained for 30 days. Except for pH, this attempt to screen waste receipts fell much too short of the intended goal.

These amendments greatly impacted the operations of many existing commercial facilities. The handwriting was on the wall: pits were soon to be a thing of the past. Facilities were now required to move forward and devise alternate treatment and disposal methods. New facilities could only be located in areas suitable for waste treatment and disposal. Existing facilities had to be retrofitted to comply with regulations which had become more protective of the environment and in concert with the desires of Louisiana citizens.

1984 Amendment

The 1983 amendment of the rule was a positive step in the direction of improved regulatory control of offsite oilfield waste disposal practices. However, as with all regulations, there still remained gaps that needed to be addressed. Some facilities were receiving questionable wastes. Land treatment facility operating requirements were vague. Pits were still operated at many sites, while others were closed. Financial responsibility (insurance) and closure funding requirements were of concern. The resource conservation and recovery (reuse) of treated nonhazardous oilfield waste

was a new idea yet to be proven. In response to these issues, Paragraph 13 was amended again in 1984. The highlights of this amendment are as follows (3):

1. As required by Act of 804 of 1980, but never addressed, "other related nonhazardous wastes generated by the drilling and production of oil and gas wells" were identified. Nonhazardous oilfield waste was defined as "waste generated by the drilling and production of oil and gas wells and which is not regulated by the provisions of the Louisiana Hazardous Waste Management Plan" as administered by a sister agency, the Department of Environmental Quality (DEQ). Such wastes included, but were not limited to the following:

   (1) Oil base or water base drilling mud and cuttings.
   (2) Salt water (produced brine).
   (3) Drilling, workover and completion fluids.
   (4) Produced oily sands and solids.
   (5) Production pit sludges.
   (6) Production storage tank sludges.
   (7) Nonhazardous natural gas plant processing waste which is commingled with produced formation water.
   (8) Produced formation fresh water.
   (9) Washout water generated from the cleaning of vessels (barges, tanks, etc.) that transport nonhazardous oilfield waste and are not contaminated by hazardous waste.
   (10) Rainwater from ring levees and pits at production and drilling facilities.
   (11) Pipeline test water which does not meet discharge limitations established by the appropriate state agency.
   (12) Pipeline pig water, i.e., waste fluids generated from the cleaning of a pipeline.
   (13) Washout pit water from oilfield related carriers that are not permitted to haul hazardous waste.
   (14) Waste from approved salvage oil operators who only receive waste oil (BS&W) from oil and gas leases.
   (15) Material used in crude oil spill clean-up operations.
   (16) Wastes from approved commercial Class II storage, treatment and/or disposal facilities.

2. Although provided for in the 1983 amendment, land treatment of oilfield waste was not defined until 1984. Land treatment was officially considered "a dynamic process involving the controlled application of nonhazardous oilfield waste onto or into the aerobic surface soil horizon by a commercial facility, accompanied by continued monitoring and management, to alter the physical, chemical, and biological state of the waste. Site, soil, climate, and biological activity interact as a system to degrade and immobilize waste constituents thereby rendering the area suitable for the support of vegetative growth and providing for beneficial future land use".

3. Land treatment operational requirements were expanded to require a conservative limit of five percent in the amount of oil and grease in a cell. This limit was set because research (4) had shown that oil and grease values of ten percent or more in oilfield waste needed special treatment if waste was to be degraded within a reasonable amount of time.

4. The resource conservation and recovery of treated nonhazardous oilfield waste was permitted on a case-by-case basis only after sufficient testing was performed. However, no testing parameters or criteria were promulgated. The primary reuse proposal at the time was for daily cover at municipal or industrial waste landfills. One pilot project was undertaken by Newpark Waste Treatment Systems, Inc. (now Newpark Environmental Services, Inc.) as treated solids were transported to a BFI landfill east of New Orleans, Louisiana.

5. Insurance policies submitted in compliance with financial responsibility criteria were required to provide sudden and accidental pollution coverage (spills) as well as environmental impairment (absolute/seepage) liability coverage for obvious reasons.

6. Companies could still use earthen pits under the 1984 amendment. However, soil permeability testing was to be performed with water as well as potentially stored fluids as the permeants. A combination of synthetic and natural materials could be utilized to construct the required liner. Levees had to be tied into the impermeable barrier (keyed) to prevent lateral migration.

7. The last reference to "good housekeeping" requirements were replaced by specific operational criteria.

1986 Amendments

Subsequent to the 1984 changes in the rules, the oil and gas industry began to feel the national push toward improved regulation of exploration and production waste management practices. The Alaska Center for the Environment sued EPA in 1985 to force the federal environmental regulatory agency to implement the oilfield waste study mandated by the 1980 RCRA amendments. In Louisiana, environmentalists continued efforts to transfer the regulation of oilfield waste from the Office of Conservation to DEQ, the agency responsible for solid and hazardous waste regulatory programs. It became necessary to close gaps in the commercial facility regulations in the areas of reuseable materials, onsite/offsite waste management documentation, location criteria, application completeness, insurance, closure funding and others. The major changes to the commercial facility regulations in 1986 are discussed below (5):

1. Definitions of key words were added or amended:

   (1) "Offsite" was added in order to identify the difference between onsite treatment and disposal of oilfield waste (where generated) and offsite disposal. Waste hauled offsite for disposal was required to be taken to a permitted commercial facility.

   (2) Nonhazardous oilfield waste was given the acronym "NOW" and certain waste stream definitions were clarified.

   (3) Reusable material was defined as "material that would otherwise be classified as nonhazardous oilfield waste, but which is capable of resource conservation and recovery and has been processed in whole or in part for reuse. To meet this definition, the material must have been treated physically, chemically, or biologically or otherwise processed so that the material is significantly changed (i.e., the new material is physically, chemically, or biologically distinct from the original material)", and meets the applicable criteria of the rule. However, specific testing criteria and guidelines were not added until 1986.

2. Over the years, several instances had been documented where generators had contracted for offsite disposal of NOW at commercial facilities and vacuum truck operators had illegally disposed of the waste at other locations. As a result, the 1986 amendment contained at least three requirements to prevent future occurrence of these acts:

   (1) Operators were required to report any unauthorized disposal of NOW when discovered.

   (2) A specific statement that the "unpermitted or unauthorized storage, treatment, disposal or discharge of NOW is prohibited" was added.

   (3) Oil and gas operators were required to document the amount and types of waste (NOW) generated during the drilling or workover of each well in the state and certify that such waste was disposed of in accordance with applicable rules and regulations of the Office of Conservation.

3. Because of concern over loss of environmentally fragile wetlands, new commercial facilities were no longer permitted to be constructed in U. S. Corps. of Engineer designated wetlands.

4. Although not specifically defined, a new application was now required when existing facilities intended to make "major modifications". Such modification was intended to mean adding new waste streams, changing or adding new NOW treatment

technologies, or expanding beyond previously permitted property boundaries. The 1986 amendment gave the public an opportunity to review and comment on proposed major facility changes at public hearings conducted in the local affected community.

5. Until 1986, all commercial facilities were required to carry a $1,000,000 environmental impairment (seepage/absolute) insurance policy. Because of the inability to obtain affordable environmental impairment insurance coverage for smaller companies with reduced liability, insurance requirements were changed as follows:

   (1) Facilities utilizing earthen pits for temporary storage of NOW were required to continue obtaining $1,000,000 environmental impairment insurance coverage.

   (2) Facilities which accepted NOW solids and conducted land treatment, incineration and physical/chemical treatment methods were required to provide a $500,000 sudden and accidental pollution liability policy as it was determined that the level of monitoring at these facilities was such that environment impairment coverage was not warranted.

   (3) Closed NOW fluid (salt water, etc.) disposal systems were required to provide a $250,000 sudden and accidental pollution liability policy for the same reasons.

   (4) Transfer stations were required to provide a $100,000 sudden and accidental pollution liability policy.

6. Although provisions for adequate closure (bonding) of commercial facilities did not see any appreciable change in 1986, the Office of Conservation had begun to provide operators with guidelines for the preparation of closure plans and cost estimates. These plans and estimates were to be prepared by a third party (consultant, etc.) and approximate the amount of funding that would be needed to adequately return a permitted site (as close as possible) to its original condition. As expected, some facilities appeared to "low-ball" their estimate while other estimates approached more reasonable amounts. In order to address this issue satisfactorily, an Injection and Mining Division engineer began reviewing recent facility closure plans and cost estimates. This work provided much higher estimates than previously calculated. Such scrutiny resulted from steps taken to close two previously permitted but now abandoned facilities.

   In both cases, it was determined that the closure funding provided would not approach the real figures needed to adequately close the sites.

7. A 1986 amendment to only permit the use of temporary storage pits for NOW solids marked the end of an era. As of early 1990, the last operational earthen pit utilized by a commercial facility was closed. At present, no existing commercial disposal site operates an earthen pit, although the rule provides specific construction (liners, etc.) and operation guidelines for temporary storage (receiving) pits. Such pits may not exceed a design capacity of 50,000 barrels and will only be approved for temporary storage of NOW in connection with a permitted treatment system (i.e. land treatment, chemical fixation, physical dewatering, incineration, etc.). Commercial pits were no longer approved for the permanent disposal of NOW.

8. Detailed application requirements for land treatment systems were added for the first time.

9. Detailed application requirements for transfer stations were also added. These guidelines stemmed from past attempts by out-of-state companies to set up barges for receipt and transport of NOW to other states (for disposal) without having met requirements in Louisiana. Transfer stations for temporary storage (30 days) of NOW by companies with in-state treatment and disposal facilities could be permitted administratively without a public hearing. Transfer stations to be operated by out-of-state disposal facilities must be permitted like any other in-state disposal company, including a public hearing in the seat of government for the affected parish.

10. Monitor well testing parameters for pits were expanded to include oil and grease, As, Ba, Cd, Cr, Pb, Hg, Se, Ag and Zn in order to be consistent with new land treatment criteria.

11. Monitoring requirements for land treatment facilities were in need of change in 1986. Three years of experience led Conservation to require more proof of environmental protection. As a result, the following criteria were added:

    (1) Specific limits for the concentration of the following metals in the treatment zone: As, Ba, Cd, Cr, Pb, Hg, Se, Ag, and Zn.

    (2) The concentration of measured constituents in any monitored shallow groundwater aquifer could not significantly exceed background water quality data. While this requirement was not definitive, it provided the needed flexibility when determining whether or not remedial action is warranted.

    (3) Baseline land treatment cell and monitor well data was required prior to the opening of a new facility or cell.

    (4) Detailed monitoring programs were required to determine the

extent of waste degradation and accumulation of metals in the waste treatment zone, the unsaturated zone beneath the cell, and ground water.

(5) Specific soil (cell) sampling protocols were outlined.

(6) Closure and post-closure maintenance and monitoring programs were to be submitted for review and approval. Closure criteria for soils in the treatment zone and surface runoff water were set.

12. Detailed guidelines and testing criteria for the reuse of treated NOW were provided to encourage alternatives to disposal; however, very little material has been approved for reuse projects since the rule was promulgated. Most reuse material was either stockpiled or utilized to construct levees of new land treatment cells in expansion programs at existing facilities. Reuse criteria was more restrictive than land treatment criteria. Specific leachate testing was an additional requirement. Treated NOW may not be offered for reuse until first shown to comply with the land treatment criteria of 29-B.

Current (1990) Issues

Since 1986, no amendments to the commercial facility regulations have been promulgated. However, several issues presently under consideration were the subject of a public hearing conducted on June 6, 1990. A rule change is expected to be published on August 20, 1990. Three of the proposed changes are presented below:

1. A change in the testing protocol for barium (Ba) analysis and a corresponding increase in the land treatment and reuse criteria for Ba are being considered. NOW studies by B. D. Freeman and Dr. Lloyd E. Deuel, Jr. (4) served as the basis for setting Ba limits in the 1986 regulations. Studies by K. W. Brown & Associates in 1987 (6) discussed the geochemistry and potential environmental impacts of Ba. In 1989, Deuel and Freeman (7) provided technical justification and recommended modifications of the Ba criteria in 29-B in a paper presented by Dr. Deuel at the SPE/IADC Drilling Conference in New Orleans, Louisiana. The Environmental Protection Agency (8) is proposing to exempt barium sulfate (a major component of drilling fluids) from the reporting requirements for toxic chemicals under section 313 of the Emergency Planning and Community Right-to-Know Act of 1986 based on EPA's review of available data on the health and environmental effects of barium sulfate. These and other documents have been placed into the hearing record as documentation of why Ba limits should be increased.

2. Specific land treatment management practices are also addressed. Waste loading will be limited to 15,000 barrels/acre during a three month application phase. Waste must be actively treated and brought into compliance with applicable criteria within twelve months of the end of the application phase. Treatment zone monitoring guidelines will require sampling in specific soil horizons. These and other changes attempt to prevent overloading of cells while allowing companies to maintain individual waste management techniques.

3. New regulations will require generators of NOW who are not oil and gas operators of record (i.e., service, trucking, and pipeline companies, etc.) to document how and where waste is generated before being approved for disposal at permitted sites. History has shown that much of this waste does not meet the definition of nonhazardous oilfield waste and cannot be accepted for disposal by. The Office of Conservation presently requires such companies to provide information in writing before approval is granted. An inspection will be performed if deemed necessary. Table 1 (Exempt/Nonexempt Wastes) of the December 1987 EPA Report to Congress is presently reviewed in addition to existing 29-B requirements to determine whether or not to approve requests to dispose of questionable wastes.

Conclusion

Primarily, the development of the commercial facility regulations since 1980 has been spurred by the need to plug regulatory gaps when discovered, by efforts of Louisiana citizens concerned about the environment in which they live, and by the oil and gas industry's concern about future liability and the uncertainty of the outcome of the EPA oilfield waste study. The Louisiana Office of Conservation can be proud of its achievements in transforming a regulatory concept in 1980 into a full-scale environmental program dedicated to the protection of human health and the environment. Many have suggested that Statewide Order No. 29-B, Section XV, Paragraph 13 will serve as a model regulation for other states to follow if future EPA guidelines require state oilfield environmental programs to be improved. Readers are invited to contact the author to receive a copy of the current or past regulations discussed herein or to discuss specific requirements for commercial disposers.

References

1. State of Louisiana, Office of Conservation, Amendment to Statewide Order No. 29-B, Section XV, Paragraph 13, July 20, 1980.

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4. B. D. Freeman, L. E. Deuel, Jr., Guidelines for Closing Drilling Waste Fluid Pits in Wetland and Upland Areas, Parts I, II, and III, 2nd Industrial Pollution Control Proceedings, 7th Annual Energy Sources Technology Conference and Exhibition, New Orleans, 1984.

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6. W. Crawley, J. F. Artiola, J. A. Rehage, Barium Containing Oilfield Drilling Wastes: Effects On Land Disposal, Proceedings of a National Conference on Drilling Muds, University of Oklahoma, Environmental and Ground Water Institute, Norman, 1987.

7. L. E. Deuel, Jr., B. D. Freeman, Amendment to Louisiana Statewide Order 29-B Suggested Modifications for Barium Criteria (SPE/IADC 18673), SPE/IADC Drilling Conference, New Orleans, 1989.

8. Federal Register, Barium Sulfate; Toxic Chemical Release Reporting; Community Right-to-Know, Proposed Rule, February 12, 1990, Vol. 55, No. 29, pp 4879-4881.

REGULATION OF NATURALLY-OCCURRING RADIOACTIVE MATERIAL IN LOUISIANA

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Introduction

For quite some time, work has been underway nationwide to provide guidance in dealing with low-level radiation from naturally-occurring radioactive material (NORM) in the environment. However, progress has been slow for a variety of reasons. One key reason for this lack of regulatory control for NORM in the past is the limited jurisdiction by the federal government, and, by default, the responsibility was passed on to the states which typically did not have adequate programs or staff to deal with the additional problem. Recently though, there appears to be a resurgence of interest by the EPA, the Conference of Radiation Control Program Directors, and several affected state agencies. In Louisiana we first started evaluating the NORM problem in 1972 at natural gas processing plants, oil refineries, phosphate, bauxite and lignite facilities. With the help of the EPA Las Vegas facility and the Eastern Environmental Radiation Laboratory we had a fairly good handle on the NORM content at these facilities.

Of particular interest to Louisiana at present, however, is the problem related to the NORM content of produced waters and the resultant contamination of equipment and facilities in the oil and gas production and support industries. The accompanying waste brine associated with oil and gas production which typically contain from 19 to 2800 pCi/l of total radium. This occurrence has been documented for well over 30 years. Of the several theories on the origin of radium in the brine, the most widely accepted is that the occurrence results from the leaching-out of the surrounding uranium-bearing rock from which the oil and associated formation waters are drawn. It has been shown that the radium can be easily extracted leaving the mineral intact. These waters flowing through drilling tubulars, pipes, and other related components, over time, result in the deposition of inorganic chemical compounds. This scale, as it is termed, restricts production, causes equipment inefficiency, impedes heat transfer, and is very time-consuming and expensive to remove. The scale problem is estimated to cost the petroleum companies over a billion dollars each year. Recently another problem with the scale formation has surfaced--the radioactivity, which may exist in concentrations up to 100,000 pCi/gm, possibly more.

Our experience has shown that not all scale is radioactive, the scale thickness and radium concentration vary from location to location, and

there's no accurate way to predict radiation levels. We know there are very large volumes of scale produced; in one large oil-producing state alone, the annual production is estimated by a recent study to be over 35,000 cu. meters. A related problem is the contamination of soil which occurs at pipe yards and pipe cleaning facilities. The cleaning operation involves a reaming, rattling, or other process which causes the dislodged scale to fall from the pipe ends to the ground. It's not uncommon at facilities which have operated for several years to observe concentrations of radium in soil of over 8000 pCi/gm.

Examples of how this problem got our attention included oil field pipe setting off radiation alarms in scrap yards and metal reclamation facilities. These monitors were originally installed to detect radioactivity in scrap metal which began to show up as a result of a Co-60 contamination incident which occurred in Mexico a few years ago; but, as it turns out, they're also quite effective in detecting pipe contaminated with radium scale. When this happens, it results in the entire load being diverted to a yard that doesn't have a monitor installed. Quite often we are notified by the original yard, but its usually impossible to locate the material once they have been turned away. Another incident which occurred two years ago involved a lost Cs-137 oil-well logging source in the Southwest portion of the state. We requested the assistance of the Department of Energy in locating the lost source. They responded with a helicopter equipped with very sensitive radiation detection instruments and began scanning a sixty-mile wide area along I-10 between the cities of Lafayette and Lake Charles. They never found the cesium source, but had no trouble at all locating several oil-field brine pits in the area. In addition reports of contaminated pipe used in construction of bleachers, school and public park playground equipment, and as work material in welding classes at Vo-Tec schools in the State have all added to a growing awareness in Louisiana of more detrimental consequences of the many years of oil production in the State.

For four consecutive days, beginning Sunday, December 11, 1988, the Baton Rouge, Louisiana, Morning Advocate carried front-page articles with titles such as "Brine Flowing in Louisiana waters is Radioactive," "Pipes Handled by Oil Workers Discovered to be Radioactive," "Oil Field Brine Radioactivity New Concern," and "Radioactive Playground Equipment Torn Down." Needless to say, this issue has received unprecedented attention over the past year and a half, resulting in positive action being taken by the regulatory agency of the State.

Health and Safety Concerns

First, and most importantly, is the element involved--radium. When this presentation was given to our Joint Legislative Committee on Natural Resources, a great deal of elaboration on radium toxicity and characteristics was provided which I don't really feel is necessary for this audience.

We are concerned that workers employed in the area of cutting and reaming oil-field pipe and equipment may be exposed to potential health risks associated with inhalation and/or ingestion of dust particles containing elevated levels of alpha-emitting radionuclides.

The potential exists for Ra-226 to enter both aquatic and terrestrial food chains leading to human consumption, due to previous lax disposal requirements for production waters.

The environmental consequences and health risks associated with disposal of NORM-contaminated oil-field wastes (e.g., incineration, land farming, and down-hole injection) are largely unknown.

Because of its long half-life, sites contaminated with elevated levels of Ra-226 will be of concern for centuries. Many of these sites, especially the pipe yards, are within city limits and could easily be used for residential or commercial purposes in the future. If buildings were to be constructed over radium-contaminated soil, the resulting radon emanation could pose a health threat.

Contaminated piping has been found in downstream usage in both private and public sectors--bleachers, gym sets, fences, welding materials, etc.

Literally billions of gallons of produced water are released annually to the environment in coastal Louisiana with very little information available on the fate of the radioactive components. Based on sample analysis and calculation, we estimate over 10 Ci of Ra-226 were released into SW Louisiana marshes from <u>one</u> oil field alone over a several year period!

There are some very difficult questions concerning potential liabilities for transfer of contaminated land for unrestricted use, worker exposure, and necessary remedial measures.

It is not uncommon to encounter pieces of oil or gas industry equipment or scale deposits that produce readings of 5-10 mrem/hr. Thus exposure to such materials for only a couple of hours could exceed the level established as a criterion for regulatory concern by the NRC.

<u>Regulatory Status</u>

Prior to September 20, 1989, there were no specific regulations in place at the state or federal level to deal with identification, handling, or disposal of NORM-contaminated materials.

The NRC, under current Atomic Energy Act authority, is limited to regulation of source, special nuclear, and byproduct materials. The Conference of Radiation Control Program Directors on numerous occasions has urged that the NRC seek legislative authority to regulate NORM. The latest effort has resulted in a referral to the Committee on Interagency Radiation Research and Policy Coordination (CIRRPC) for evaluation and a request for response back to NRC in 18 months--early 1990. The scope

however, is limited to discrete sources of Naturally-Occurring and Accelerator-produced Radioactive Material (NARM) which usually includes only those products to which natural or accelerator-produced isotopes are purposely added for their radioactive properties.

The EPA, in 1978, proposed that any industrial by-product that contains greater than 5 pCi/gm Ra-226 be classified as hazardous waste, but the rule was never promulgated. Then, in 1988, they stated that wastes such as produced water, sands, drilling muds, and cuttings were not to be classified as hazardous waste. More recently a level of 50 pCi/l of radioactivity in liquids has been proposed as a criterion for hazardous waste. In EPA's proposed LLW rule, discrete NARM and diffuse NORM is included when the concentrations of radioactivity exceed 2000 pCi/gm.

The CRCPD Part N Committee on regulations has developed a set of proposed Suggested State Regulations for NORM, now in its 7th draft. If adopted following the state and federal review process, it will be available for states to use at their option. If adopted by all states, this would ensure uniform regulations, however not all states feel they have the necessary enabling legislation to regulate NORM, and it is unlikely that all provisions would be acceptable by all agencies concerned. This rule sets a regulatory limit of 5 pCi/gm.

OSHA, in a recent communication to the LA DEQ, has indicated that they are considering mailing a health hazard alert to their Regional and Area offices concerning oil-field wastes.

The LA DEQ in October 1988, released an Interim Policy on the handling, storing and disposing of scale or soil contaminated by the cleaning of pipe. It included a background discussion of the problem, worker protection guidelines, NORM storage options, and it prohibited transfer of contaminated items to other individuals. This guidance preceded release of an Emergency Rule on February 20, 1989, which amended the Louisiana Radiation Regulations by adding a chapter entitled, "Regulation and Licensing of Naturally-Occurring Radioactive Materials (NORM). It was distributed to over 1200 potential licensees in the State. Following several months of review by technical committees, two rounds of public hearing and comments, and a favorable vote by the House and Senate Committees on Natural Resources, the permanent Rule was adopted, and Louisiana became the first state to promulgate NORM regulations.

Scope of the Regulation

The exemption criterion initially used in the case of the Emergency Rule was radium concentrations less than 30 pCi/gm. This number was derived from the Appendix A, Table II, Column 2 of the Suggested State Regulations for unrestricted release of insoluble Ra-226 to water, assuming soil or scale and water have approximately the same density, and changing ml to gm. This was done for lack of a better number and is not entirely appropriate; nor is it easily determined in the field. It was necessary to obtain a sample of material, and run a time-consuming, complicated, and somewhat costly laboratory procedure. This was

particularly burdensome to the smaller, independent producers who had absolutely no familiarity with radioactivity. Based on this problem and the many comments we received, the decision was made to change from a concentration level to a radiation exposure level of 50 urem/hr. This change would facilitate field measurements for the hundreds of potentially affected locations and equipment, lower the cost of determination of applicability, and still provide an acceptable level of radiation protection for workers. This level of exposure, if received continuously, would not exceed the 500 mrem/yr figure. To assure ourselves that we chose a proper dose level, we are analyzing scale from the large number of tubulars that have been screened and fall into category of bkg-50 urem/hr and which would not normally require cleaning under the exemption criterion. We should have this information available by early summer.

Other exemptions include the phosphate fertilizer industry products and by-products, and bauxite processing, since these are already covered by existing LA regulations. Also retail distribution of natural gas, crude oil, and their products were exempted, as were produced waters, since these are being regulated by the Water Pollution Control Division of DEQ. Any person not exempted under one of the criteria automatically becomes a general licensee of the State, subject to all applicable portions of the Louisiana Radiation Regulations. In many cases, a specific license will be required, particularly for pipe cleaning and decontamination operations.

Other Requirements

In order to determine applicability, a radiation survey must be performed within 180 days of the effective date of the Regulation. It specifies that the instrumentation used be capable of measuring 1 urem/hr through at least 500 urem/hr, and be calibrated semiannually and at energies appropriate to use, with accuracies within +/- 20% of the true radiation level.

The Rule prohibits release of NORM-contaminated facilities and equipment for unrestricted use, and it requires that decontamination and maintenance of such equipment be performed only by specifically authorized persons whether conducted on or off-site.

Also prohibited is the unrestricted transfer of land where the concentration of Ra-226 in soil, averaged over any 100 sq meters, exceeds the background level by more than 5 pCi/gm averaged over the first 15 cm of soil and 15 pCi/gm averaged over 15 cm thick layers of soil more than 15 cm below the surface. This requirement was already in our existing regulations, but it was repeated here because of its applicability with respect to NORM contamination.

Finally, an initial fee and an annual maintenance fee of $100, payable for each NORM General Licensee location, were incorporated in the regulations.

Surveys

I had hoped to be able to provide data on surveys conducted by the Division, as well as by licensees, but, due to the delays in promulgation of the Rule, none are available at this time.

Conclusion

One impact of the new Regulations which is readily observable has been the emergence of a new growth industry in the State--the pipe cleaning business. We have authorized five companies to operate thus far, and expect several new applicants in the near future. The problem is that we continue to receive reports of clandestine operations across state lines, out of our jurisdiction, and reports of companies not willing to comply until confronted face to face. I think the eventual outcome will be compliance, as a result of legally operating companies learning of their illegal competition and reporting such actions to the regulatory authorities.

On a positive note, we have received funds to run the program, established several new positions, distributed the Rule and other information to most of the affected industry, and are receiving a satisfactory response.

We have recently completed and distributed a NORM Regulatory Guide for use in conducting confirmatory surveys for general licensure determination and for use in cleanup operations and closeout surveys. We would be pleased to provide copies to any interested states. We have also prepared a licensing guide for use by applicants for specific licenses to conduct NORM decontamination and maintenance operations. We have authorized five (5) companies to perform pipe de-scaling as a service to oil and gas industries, but have not yet issued a specific license. We are inspecting these operations and evaluating their performance to determine what license conditions are appropriate. We want to see if any build up of radioactive material in the system occurs after several months of operations and what concentrations are present in the filters and process waters.

Ultimate disposal of the residue is a major problem at present. Pipe cleaning facilities are required to collect and return all removed scale and residue to the customer where it is stored indefinitely in DOTD-approved and permanently marked drums. So far only a limited number of shipments have been made to Envirocare, the NORM disposal facility in Utah, but we expect to see more as the volume grows, long term storage becomes burdensome, and pooling of the waste by the major oil producers is accomplished.

Other disposal options that have been reviewed on a case by case basis include down-hole disposal of contaminated tubulars and sludge in abandoned wells and incineration of contaminated soil and reserve pit residue followed by dilution with uncontaminated fill. The State Office of Conservation has a requirement that all oil production reserve pits

in the coastal zone be closed out by 1993. The closure criteria require adherence to our NORM Reg Guide. We are adding a chapter to the Guide requiring that final radium concentration in the closed pit not exceed 30 pCi/g.

REGULATIONS AND POLICY CONCERNING OIL AND GAS WASTE MANAGEMENT PRACTICES IN INDIA

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Introduction

Petroleum Products

The demand for petroleum products in India is estimated to increase from 58 million tonnes at present to 127 million tonnes by 2004-05. The domestic crude production would rise from 35 million tonnes at present to 75 million tonnes by 2000. This speaks of the magnitude of enhancement of generation of waste due to (i) exploration, and (ii) exploitation for domestic production, (iii) refining of crude oil of both indigenous and imported origin and (iv) consumption of petroleum products in the down stream industries.

Natural Gas

Today, natural gas reigns supreme in Indian energy scenario and Indian future economy is planned to be decidedly gas based. The shift is envisaged in favour of growth of gas-based low energy intensive - high value added as against high energy - low value added industries.

It has been established that the petrochemicals have the highest value addition in the use of natural gas as is demonstrated through the figures presented in Table 1.

Table 1

Value Addition in the Use of Natural Gas

(In Rupees)*

Gas to	Per NM^3 of gas	Per tonne of gas	Per tonne of product/MWH
1. Petrochemicals	8.21	8,932	11,328

* 1 US$ = Rs.17.25

2. Petrochemicals (olifin stage only)	3.60	3,914	6,106
3. Power generation	2.08	2,268	613.5
4. Fertilisers	1.42	767	600.00
5. Fuels	1.15	1,255	1,255

This has, obviously, moved priority in favour of use of natural gas in the manufacture of petrochemicals.

Production of natural gas is expected to grow five folds faster than oil. A long term production and utilisation plan has been prepared for the optimal consumption through a National Gas Grid. This would reduce regional imbalances by inter-connecting the low demand - high supply areas to the high demand - low supply areas thus meeting the requirements of various industries like petrochemicals, fertilisers, power and a host of others besides its domestic use.

This future plan for gas exploitation and utilisation is amply supported through the ever-swelling reserves of natural gas. Against prognosticaled resources of 63.15 billion m^3 gas in 1966, the established reserves of present are 1103.58 billion m^3 - available both as free and associated gas.

	Reserves of Natural Gas (billion m^3)
1966	63.15
1970	62.48
1975	87.67
1980	351.91
1985	478.63
1988	1103.58

The continued increased usage of natural gas is taking the weight off the demand for imported petroleum products. It has helped bring about a saving of Rs.16,270 million in foreign exchange per year during the period 1986 to 1988. With new thrust being imparted to production and utilisation of natural gas, the total foreign exchange saving during 1989-90 is expected to touch a record of Rs.20,000 million. Such a phenomenal growth is attributed to replacement of naphtha/fuel oil and solid fuels as feedstock and fuels in various sectors such as:

i. <u>Feedstock</u>

Fertilisers/Petrochemicals:

iii. <u>Power</u>

Captive:

Cracker grade naphtha, fuel oil, coal

Diesel (HSD)

Peak & Base Load:

Diesel, coal, fuel oil (LSHS)

ii. Energy

Industrial (e.g. sponge iron):

Fuel oil, diesel, coal
LPG, kerosens, coal, diesel, wood

Stationery Engine:

Diesel

iv. Transport

Buses/Cars:

Petrol, diesel

Diesel Locomotives:

Diesel

The present rate (1988) of production of natural gas is 40 million m^3/day and the committed consumption is for only 38 million m^3/day, segregated as below:

Present commitment for use of natural gas (rich gas)	Million m^3/day
Users along HBJ pipeline	17.1
Consumption at Bijapur/Swaimadhopur	6.4
Consumption at Auraiya	10.7
Others	3.8
	38.0

On an annual basis it works out to 13,870 million m^3 or 13.87 billion m^3/year. This accounts for only 1.25% annual rate of depletion of established reserves of gas and this is considered quite low by any standard.

The country's gas production level is projected to go up significantly to reach a level of around 120 million m^3 a day from the present figure of 40 million m^3 a day (1990-91). From these data, it is evident that a major focus and attention towards planning of integraded field development, large national gas grid and optimal utilisation of natural gas resources have assumed national priority.

The present (1990-91) broad pattern of gas use favours fertiliser industry:

	(Percent)
Fertiliser industry	45
Power generation	35
Internal use	17
Industrial & domestic fuel	3
	100

Over the past few years, a number of commitments have been made for the power sector and some more are likely to materialise. It is thus possible that share of power sector would increase during Eighth Plan (1990-91 to 1995-96) while that of the fertiliser would go down. However, these sectors would continue to have dominant share of the natural gas used in the country. The use of gas for sponge iron and gas based petrochemical complex, would be the new features of future usage of gas. Nagothane gas-base petrochemical complex of Indian Petrochemicals Corporation Ltd. (IPCL) and Hazira Sponge Iron (0.8 million tonnes annual capacity) of ESSAR Ltd. based on natural gas have already gone into production. Experiments are also in advanced stage for use of natural gas in transport. Taking these aspects into consideration, the use pattern of gas is expected to undergo a change and that will change the pattern of generation of waste due to the use of natural gas:

	(Percent)
Fertiliser	33.50
Power	41.30
Industry (Petrochemicals, sponge iron etc.)	12.00
Transport	9.80
Domestic	3.40
	100.00

Waste Generated by Indian Oil & Natural Gas Industry

Flaring of Natural Gas

Ever increasing volumes of gas continue to be flared up as indicated in Table 2.

Table 2

Gas Flared in India

(Million m^3/year)

	Gujarat	Assam	Off-shore	Total
1970-71	155	607	-	672
1974-75	121	830	-	951
1979-80	178	616	170	964
1984-85	85	1,074	1,893	3,054
1987-88	288	735	2,439	3,442
1989-90	290	812	2,575	3,677

This is attributed to (i) short lifting of committed supplies of gas by consumers and (ii) delay in commissioning of gas-based power, petro-chemicals and fertiliser plants.

Steps Suggested for Economical Usage of Gas Flared

The measures proposed to reduce gas flaring include (i) reducing crude oil production (ii) setting up of more facilities for processing natural gas and (iii) a new gas use policy. These options are evaluated in the light of following justifications:

(1) It is estimated that India will have to reduce crude oil production by about 3 to 4 million tonnes or by 11.6 million tonnes over a three year period if it wants to completely stop gas flaring by March 1993. This would mean that crude oil imports will go up by the same quantity.

The option appears hard due to the lean position of the present foreign exchange resources of the country. Prevention of flaring of 11.03 billion m^3 of gas over a period of 3 years valued at Rs.30,000 million, appears sound on the domestic front.

In the event of above option, Indian Oil Corporation (IOC) which is the canalising agency for import of crude oil and petroleum products may go for a bridge loan from international commercial sources for import of additional crude oil to make up for the reduction of 11.6 million tonnes of domestic production. The interest charges on a loan like this work out at 8 to 10 per cent. But loan saves gas valued at Rs.30,000 million over 3 years period.

(2) The time between now and March 1993 is proposed for setting up of processing facilities and down stream units to utilise the gas.

(3) A new gas utilisation policy which permits greater utilisation of gas needs to be formulated now. At present, gas is reserved for fertiliser plants taking into account their requirement for 30 years. It is suggested to reduce this period to 20 years. Such a step will spare gas for other far more needy industries.

Exploration and Exploitation of Oil and Natural Gas

The main waste generated during exploration is drilling fluid effluent.

International statistics show that 1 m^3 of drilling fluid effluent is produced on an average for every metre drilled. A good quantity of it is evaporated in normal process particularly during summer in a tropical country like India. During monsoon when evaporation is less, the problem of accumulation of waste water becomes more discernible.

The problem is encountered in three ways (a) recycling of mud pump coolant water, (b) recycling of effluent water for preparation and (c) treatment of effluent water for re-use.

Contribution of Refineries in Generation of Waste

The refinery at Digboi in Assam commissioned in 1901 is perhaps the oldest operating refinery in the world. However this was the only refinery in India till mid-50s. Between 1954 and 1982 eleven refineries were commissioned which enhanced the refining capacity from 0.3 million tonnes per annum (MTPA) to 51.9 MTPA by 1989.

The refineries have been providing the pollution abatement facilities right from the design stage itself. However the facilities provided in the various refineries differ from each other since these are governed by concurrent

- regulations
- technologies available and
- operating parameters.

As for instance the last refinery commissioned in 1982 has also tertiary treatment in addition to effluent treatment plants having physical, chemical and biological treatment facilities.

Wastes Generated and their Treatment in Refineries

The waste water generated at the different stages of refinery is treated in accordance with the well laid down procedure and similarly there are standard prescribed for the air pollution (Table 3).

Table 3

Oil Refineries - Emission Standards for Sulphur Dioxide

Process	SO_2 Emission Limit
(a) Atmospheric and vacuum distillation	0.25 kg/tonne of feed
(b) Catalytic cracker	2.5 kg/tonne of feed
(c) Sulphur recovery unit	120 kg/tonne of sulphur in the feed

The solid waste generated in Indian refiniries are of great concern. These solid waste are:

- Sludge formed inside crude storage tanks.
- Chemical sludge generated from effluent treatment plants containing mostly iron sulphides.
- Biological sludges from activated sludge units of effluent treatment plants.

Refineries adopt melting pit system to recover oil from oily sludge. The residual sludge is stored in an open quarry inside refinery premises.

Some refineries have adopted hot gas oil circulation in crude oil tanks to dissolve oil in the sludge as much as possible and then to process in units.

Side Entry Mixers are being installed in all crude tanks in phased manner to prevent sludge formation in tanks.

At present there are no regulations governing generation, use and disposal of sludge in India. These are urgently warranted at present.

Development of a process to recover useful components from sludge will help to avoid the problem of sludge accumulation in the refinery.

Fertiliser/Petrochemical Industry

Naphtha, fuel oil and natural gas are used as feedstock as well as fuel in the fertiliser/petrochemicals industries of India. No waste as such is generated in the fertiliser industry through the consumption of naphtha/fuel oil/natural gas since the entire

feedstock which is hydrocarbon is totally broken (by burning) into Co, Co_2, H_2, inert gas etc. however, conversion of these gases into ammonia and then to urea does generate wastes due to processing and use of chemicals in process and in utilities.

The main sources of generation of liquid effluent are

- Ion Exchange Columns and
- Cooling Tower Blowdown.

Both these types of effluent are totally recycled in the captive phosphatic plants.

The pollutants in the atmospheric emission is very much within the specifications of the consented limits and recovery of these minor quantities are beyond economic consideration.

Table 4

Fertiliser Plants - Emission Limits for Particulate Matter and Flurides

Product	Process	Pollutant	Emission limit (mg/k cu.m)
(a) Urea	Prilling Tower	Particulate	50
(b) Phosphatics	Acidification of rock phosphate	Fluorides	25
(c) Phosphatics	Granulation and grinding	Particulates	150

The solid waste like spurt catalyst is disposed off by sale. The buyers retrieve the metals (Cu, Zn, Ni) content in the catalyst.

Petrochemicals Industry

Petrochemicals in India is also based on naphtha/fuel oil/natural gas as feed. In this case also no waste is generated as such through the use of hydrocarbons. Chemical waste is generated in the process.

It is suggested by the industry that for the safe disposal of chemical waste, it will be necessary to have land fill areas designated by the Government and/or providing incentives to private sector to set up large commercial incinerators.

Adequacy of Indian Law to Check Generation, Storage and Disposal of Waste of Oil and Natural Gas Industry

The Appendix 1 furnishes the salient features of the Indian legislation governing the industry to operate within the standards prescribed. A perusal of these legislation does not spell out any specific provision devoted to generation, storage and disposal of waste of oil and natural gas industry. This is a serious matter and deserves attention in view of the phenomenal increase in the consumption of oil and natural gas anticipated in future as discussed earlier in the paper.

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5. Government of India (GOI), Water (Prevention and Control of Pollution) Act 1974 with Amendments made in 1988.

6. Government of India (GOI), Air (Prevention and Control of Pollution) Act 1981 with 1987 Amendments.

7. Government of India (GOI), Environment (Protection) Act 1986.

8. Marpol Convention, Five Annexures.

Green Arm of the Law and its Adequacy

Three important Indian legislations presently enjoin industry to remain within the pollution control standard set by the Government.

1. Water (Prevention and Control of Pollution) Act 1974, with amendments made in 1988.

   - Following the 1988 amendments permission is necessary to set up any industry which is 'polluting' - one that uses or discharges any poisonous, noxious or polluting matter. Standards must be those set up by state pollution boards. Industries set up prior to the amendment need to obtain clearance within three months of its coming into force.

   - State Pollution Control Boards (PCB) have the power to obtain information regarding the construction installation or operation of any process of the industry.

   - After the 1988 amendments, the PCBs can issue directions or orders for closure or stoppage of electricity or water supply if standards are not being met by the polluting industry.

   - Penalties for non-compliance have been increased to Rs.10,000 for defaulting and Rs.5,000 per day for continued default.

2. Air (Prevention and Control of Pollution) Act 1981 with 1987 Amendments

   - The definition of air pollutant was extended from harmful solid, liquid or gaseous substances present in the atmosphere to include noise pollution.

   - Unlike the practice earlier, now all air polluting industries must have the sanction of their respective PCBs.

   - After amendments, power have been given to PCBs to issue directions for stoppage of electricity etc. for violation of standards set.

   - Penalties are as those in the Water Act.

3. Environment (Protection) Act (EPA) 1986

   - The Central Government has the power to take all such measures as it deems necessary or expedient for protecting the environment.

- Section of 3 of EPA empowers the Central Government to

(a) restrict areas in which any industry, operation, process or class of industries can be carried out under certain safeguards.

(b) lay down procedures and safeguards for the prevention of accidents which may cause environmental pollution and remedial measures for them.

(c) lay down procedures for handling hazardous substances.

(d) examine manufacturing processes and materials and

(e) wide-spread inspection powers.

As in other two acts; the EPA gives the centre wide powers to direct closure, prohibition and regulation of any industry if it contravenes the acts provisions.

In addition, the Marpol Convention, pertaining to marine pollution control, was drawn up by the International Maritime Organisation, a United Nations agency and ratified by India in 1978.

The five Annexures of this convention deal with (a) prevention of oil pollution, (b) prevention of pollution by noxious liquid substances in bulk, (c) prevention of pollution by noxious packed substances, (d) pollution from sewage and (e) from garbage.

The Indian Government has ratified only the first two Annexures. Thus a vessel can be penalised for oil or chemical pollution. But the remaining forms of pollution are unchecked.

A REVIEW OF STATE CLASS II UNDERGROUND INJECTION CONTROL PROGRAMS

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Introduction

Over the past few years, the Underground Injection Practices Council and the Underground Injection Practices Council Research Foundation have entered into a series of individual grant agreements with the U.S. Environmental Protection Agency, the U.S. Department of Energy and the American Petroleum Institute. These grants were obtained to evaluate and assess state underground injection control (UIC) programs as to their effectiveness in protecting underground sources of drinking water (USDWs) from contamination resulting from the operation of injection wells related to the production of oil and gas (Class II injection wells). Class II injection wells are used for the injection of fluids into oil reservoirs for the purpose of stimulating or furthering their production when natural production mechanisms decline or cease (enhanced recovery wells); and for the disposal of waters produced in conjunction with the production of oil and gas (disposal wells). If improperly constructed, operated, maintained, or abandoned, such wells may allow contaminants to enter USDWs, potentially depriving the public of needed current or future water supply resources.

Six state Class II UIC programs have been reviewed to date. In their review order they were California, Texas, Louisiana, Ohio, Oklahoma and Kansas. Of the approximate universe of 177,000 Class II injection wells nationwide, the states reviewed regulate over 120,000 of these wells or approximately 68% of all Class II wells. The six state programs examined were those where primary enforcement authority had been delegated to the states by EPA, under provisions of the Safe Drinking Water Act and EPA regulations.

All state program reviews were conducted in a similar manner. An investigative team of two "peer" state UIC directors comprised each review team along with a UIPC consultant, who is a former state oil and gas

director, and the UIPC Technical Director. The UIPC Technical Director and the UIPC consultant were present at each of the six state reviews to provide continuity and assure investigative integrity for the project. The state to be reviewed was required to complete a comprehensive questionnaire detailing important aspects of its Class II UIC program. This questionnaire was designed to yield an in-depth description of the seven key program elements common to all state Class II UIC programs. Those seven basic program elements were as follows; (1) permitting and file review programs, (2) inspection programs, (3) mechanical integrity testing programs, (4) compliance and enforcement programs, (5) plugging and abandonment programs, (6) inventory and data management programs, and (7) public outreach programs. After the state's completion of the questionnaire, an on-site, week long review was scheduled, whereby the review team questioned employees of the state UIC regulatory agency extensively about the operation of the various Class II program elements for which they were responsible.

Preliminary results of the review teams investigations were orally presented to the state program managers at the end of the on-site review. These were followed by a formal written review team report for each state. The review teams's comments reflect their judgement as to whether or not the state UIC program effectively protects USDWs from contamination by Class II injection wells. Additionally, state program strengths, as well as recommendations for areas of improvement, were included in the final reports.

Goals

The purposes and objectives of the Class II peer review project were multifold. As previously stated, the major objective of the project was to examine the effectiveness of each state UIC program to protect USDWs from contamination by oil and gas related injection wells. Secondly, this process provided an increased knowledge of specific state Class II regulatory programs and operations for review by other state UIC programs, the EPA and for the review participants. Additionally, the peer review project enabled the states and the UIPC to prepare for the EPA Mid-Course Evaluation of the state Class II UIC program. Lastly, this project provided the states with an independent evaluation, separate from EPA oversight, and an opportunity to examine and consider the recommendations of this review for potential implementation into their present program.

Process

The six state Class II UIC program reviews were all conducted using the same review questionnaire workbook. The workbook consisted of a series of detailed questions (153 in all) pertaining to the seven basic program elements described earlier. To assist the states in understanding the type of response desired, each series of questions was preceded by a specific objective which defined and clarified the intent of the questions. The review questionnaire was furnished to the state Class II agency to be completed by state UIC program personnel well in advance of the on-site

review.

Upon selection, the review team was given copies of the completed state workbook, for examination prior to traveling to the state being reviewed. The week long on-site review consisted of using the completed workbook as a guide while questioning state Class II UIC employees about the operation of the various program areas as outlined in the workbook. An initial background briefing on the state's geology, hydrogeology and standard UIC program procedures was provided by the host state prior to review team questioning. Additionally, the review team received a complete tour of the UIC offices, in order to evaluate workflow and output.

The review team assessed the written workbook responses, the oral responses to additional questions posed during the on-site review, and the various documents supplied by the state prior to summation of an initial list of program strengths and concerns. This summation was delivered to the State UIC Director, UIC staff, regulatory agency management, and interested parties at an exit interview on the final day of the on-site review. This exchange of information and opinions was integral to the success of the peer review process. It was this discussion of program strengths and concerns, as identified by the review team, which provided input for the state to potentially acknowledge program areas, through which minor enhancement, could make the program more efficient and effective.

Subsequent to the on-site visits, review team members wrote more extensive reports of their findings and conclusions. These reports were reviewed by the contractor and the UIPC Technical Director and submitted to the state for final comment. The review team reports were arranged in the same order as the questionnaire and each of the seven program areas was followed by a listing of any strengths or other considerations identified by the review team. The review team conclusions relative to the effectiveness of that portion of the state's UIC program to protect USDWs followed the strengths and other considerations discussion. An executive summary preceded each state specific report along with a general program comments and observations section. In the general comments section each state was provided an opportunity to list any program accomplishments since acquiring EPA approved regulatory authority (primacy). The final written reports were printed and published for dissemination to interested parties. These detailed individual state reports are available through the UIPC office.

State Report Overview

The following is a brief summary of the review team reports for each state reviewed, beginning with the initial California report and continuing through each subsequent state reviewed in its order of occurrence. State program highlights or strengths identified by the review teams are presented as well as any other considerations suggested by each review team.

The California Division of Oil and Gas UIC Program

The review of the California Division of Oil and Gas Class II UIC Program was conducted in Sacramento, in March, 1988. The Division's UIC program is much more decentralized than most state programs with permitting, file reviews, and most compliance functions handled at the district office level. The overall UIC program coordination between the districts and the Sacramento office is excellent.

The review team found good permitting procedures, qualified personnel, good availability of technical expertise and resources, excellent cooperation between the Division of Oil and Gas and other concerned state and local jurisdictions, and continuing oversight of ongoing operations. The permitting portion of the UIC program was determined by the review team to be protective of USDWs. A minor concern with long term financial responsibility for noncommercial injection wells was noted by the review team. It was suggested that this program area be given continued monitoring and study, not necessarily any immediate action.

The Division inspection program was determined to be very strong. Well defined inspection strategies, use of well qualified field personnel, and continued job related training opportunities provide the basis for an effective UIC inspection program. This program area was determined by the review team to provide good to excellent protection of USDWs.

The review team determined that the overall frequency of mechanical integrity testing, reliance on mechanical logging techniques, technical procedures employed and well trained personnel in this program area result in superior protection of USDWs. A minor concern was expressed relevant to a perceived extended period of permitted shut-in for injection wells which have failed their mechanical integrity test. A reasonable time limit was suggested for such wells to be repaired or plugged to ensure they do not threaten fresh waters or USDWs.

The policies and procedures employed by the Division to handle compliance and enforcement issues are reasonable and responsible. The Division uses a staged enforcement approach which generally achieves voluntary compliance but which can advance to formal enforcement and fines as necessary. The review team concluded that the Division has structured its UIC compliance and enforcement program to provide good protection to USDWs.

The California Division of Oil and Gas plugging and abandonment practices are conducted in a manner protective of fresh waters and USDWs. Essentially every injection well is inspected during the plugging process and setting and tagging of 80 percent of the most critical plugs is witnessed by state inspectors.

The Division has and uses appropriate data management techniques to provide better program management and inventory data. This information is available

in the district offices as well as the Sacramento office. The review team determined that the use of the Division data management system enhances the protection of USDWs.

The review team found the Division to be operating an aggressive public outreach program to promote public awareness of injection operations. The program makes use of pamphlets, video tapes and public appearances to promote public exposure of the program. The public outreach program as practiced by the California Division of Oil and Gas was deemed highly effective and supportive of the protection of USDWs.

The Texas Railroad Commission Oil and Gas Division UIC Program

The review of the Texas Class II UIC program was conducted in Austin, in July, 1988. The Texas UIC program is the largest UIC program in the country covering over 15,000 operators and 53,000 injection wells. The UIC Section of the Oil and Gas Division is solely responsible for permitting, file reviews, mechanical integrity test scheduling and evaluation, and reporting to the EPA. The UIC Section coordinates with other Division sections on matters related to budgeting, personnel, mapping, records, compliance hearings, and inspections. There is an excellent degree of cooperation and coordination of efforts between all of the various Oil and Gas Division sections which ultimately promotes the protection of USDWs.

The review team found good permitting and file review procedures, highly qualified personnel, good cooperation between state water protection agencies, and good post permitting oversight. With a single concern expressed relative to the examination of area of review wells, the review team found the permitting program element protective of USDWs.

The review team concluded that the state UIC inspection program was facilitating protection of USDWs. Inspections are performed by state employees operating from district offices. Inspection personnel are well trained and well equipped to perform their tasks efficiently and effectively. The review team did note that due to program size, the injection well to inspector ratio was approximately 1720 injection wells to each inspector, which was considered high.

Texas utilizes annulus pressure tests and annulus pressure monitoring combined with the review of cement records for mechanical integrity determinations. The review team determined that this portion of the Texas program was being conducted in a manner protective of USDWs.

The Texas Railroad Commission has a sophisticated compliance and enforcement program which is logical, well defined and effective. Written policy provides inspectors with specific enforcement procedures to clarify their role in enforcement actions. The enforcement and compliance program as conducted by the Commission is highly effective in achieving compliance with state rules. The review team acknowledges this level of excellence and

considers this program area to be very effective in achieving compliance and facilitating protection of USDWs.

The Texas state plugging requirements should result in all Class II injection wells being plugged in such a manner as to isolate and/or protect all usable quality water zones, oil, gas and geothermal zones, and USDWs. Although the review team indicated a desire to have a greater number of injection well pluggings witnessed, it concluded that the state plugging program is protective of USDWs.

The Texas Class II UIC program operates a highly sophisticated UIC data management system that provides an excellent management tool for the 53,000 injection wells in the state. The review team concluded that the data management program element of the Texas Class II UIC program readily lends itself to the support of the protection of USDWs.

The review team believes the Commission has established a reasonable and effective public outreach program. The Commission is responsive to specific public concerns through direct visits and presentations by appropriate staff on an "as needed" basis.

The Louisiana Department of Natural Resources Office of Conservation UIC Program

The Louisiana Class II UIC program review was conducted in Baton Rouge, in October, 1988. The Injection and Mining Division of the Office of Conservation has overall responsibility for permitting, file reviews, mechanical integrity test scheduling and evaluation, compliance hearings, field inspections of commercial disposal wells and reporting to EPA.

The Division's permitting program is clear, concise and easily understood. Permit applications are quickly entered into the UIC data management system and tracked to expedite permit determination. Qualified personnel are employed to assure permitting operations are smooth and efficient. The review team concluded that the permitting portion of the UIC program is conducted in a manner which is protective of USDWs.

The Louisiana Class II inspection program places a high priority on witnessing mechanical integrity tests, with less emphasis placed upon well construction and remedial work inspections. Inspectors are well qualified with a minimum of three years of oil and gas related field experience and 6 months of on the job training with an experienced inspector. The review team determined that given the number of inspectors (32 for noncommercial wells) the inspection program element is carried out in a manner that provides protection of USDWs. However, it was suggested that any action which would result in the increase in number of inspectors and UIC inspections would enhance this program area.

The Louisiana UIC mechanical integrity testing program is designed to assure

all wells are tested as required with a high level of state supervision. Based upon these measures, the review team concluded that this portion of the state UIC program is conducted in a manner which is protective of USDWs.

The compliance and enforcement program element is a strength of the Louisiana overall program. The Injection and Mining Division has the authority to administratively assess monetary fines and this authority provides an effective deterrent to non-compliance by operators. Inspectors are given broad ranging authority to seal or shut-in wells found to be in non-compliance. The review team determined that the compliance procedures and policies used by the Division are conducive to the protection of USDWs.

Louisiana witnesses about 90% of all injection well plugging operations, giving the Division good oversight of this program element. All plugging procedures must be approved by the state. Plugging requirements may differ for nearby production wells, leading to a concern on the part of the review team as to a lack of uniformity in the required setting of plugs in abandoned production wells versus injection wells.

The Class II UIC program in Louisiana makes good use of data management systems to enhance its ability to record, retain, and retrieve well and permit data in a timely and complete manner. The data management system and practices of the Division greatly enhance the protection of USDWs.

The level of public outreach by the Louisiana Injection and Mining Division is appropriate to current needs and in no way diminishes the protection of USDWs.

Ohio Department of Natural Resources Division of Oil and Gas UIC Program

The fourth Class II UIC program review was conducted in Columbus, in February, 1989. Permitting, file reviews, data management, formal compliance, hearings and program administration are handled from the Division office. Field activities are conducted from four field offices. The Division makes no distinction between the definition of fresh water and USDWs.

Ohio permits three types of injection wells: conventional disposal wells, enhanced recovery wells and annular disposal wells. All wells in the state operate under permits. The review team found good permitting and file review procedures and qualified personnel with the necessary technical expertise and resources to assure permit applications are properly handled. Minor concerns were expressed relative to long term financial assurance and the use of prepared clay as a sealant behind surface casing. With these exceptions, the review team concluded that the permitting portion of the UIC program is protective of USDWs. The use of prepared clay has recently been banned as a surface casing sealant for annular disposal wells.

One statewide UIC Field Operations Supervisor oversees all UIC inspectors.

Conventional disposal and enhanced recovery wells are routinely inspected every four to six weeks. The review team determined that the inspection area of the UIC program is providing an excellent degree of protection for USDWs.

Ohio utilizes positive pressure tests, annulus pressure monitoring and cement record evaluation for mechanical integrity determinations. All conventional injection well mechanical integrity test are witnessed by state inspectors. Mechanical integrity tests are now required prior to initial injection in annular disposal wells. The mechanical integrity testing portion of the Ohio UIC program is being conducted in a manner which is highly protective of USDWs.

The compliance and enforcement program of the Ohio Division of Oil and Gas is a multi-level, staged approach, with a variety of enforcement actions to handle violations. Fines must be sought in the courts through civil or criminal actions. The review team concluded that the compliance and enforcement program area is effective and being administered in a manner to achieve protection of USDWs.

Well plugging and abandonment must be conducted in a manner approved by either the Division of Oil and Gas or the Division of Mines. The Division of Mines oversees plugging in coal bearing townships. While the review team would like to see the state amend the split plugging authority to allow for joint plugging of injection wells they felt the plugging regulations being enforced are designed to be protective of USDWs.

At the time of the Ohio review the Division's data management systems were under extensive revision. The revised system will allow more ready access to UIC data, manipulation of data and more efficient program administration. The review team concluded that the new data management system will enhance the protection of USDWs.

The Ohio public outreach program is strengthened by the high degree of personal contact with the regulated community through frequent inspections and presentations. The review team concluded that Ohio conducts an appropriate and effective public outreach program.

The Oklahoma Corporation Commission Oil and Gas Division UIC Program

The Oklahoma Class II UIC program review was conducted in Oklahoma City, in March, 1989. The UIC Department of the Corporation Commission is completely responsible for permitting, file reviews, mechanical integrity testing, and reporting to the EPA. The Department coordinates with other Oil and Gas Division sections on matters related to budgeting, personnel, mapping, records, hearings, and inspections. There is a good degree of cooperation and coordination of efforts between all of the branches of the Oil and Gas Division leading to accomplishment of the protection of USDWs. The Oklahoma Class II UIC program was the first such program approved in the country.

The review team found good permitting and file review procedures, qualified personnel and improving post permitting oversight. Use of data processing to track permit application flow facilitates this process. Minor concerns were expressed relative to the adequacy of cement thickness above the injection zone and procedures followed on file reviewed wells when the surface casing did not extend to or through the base of the USDW. With the above mentioned concerns the review team concluded that the permitting portion of the program is being carried out in a manner that is protective of USDWs.

Although there is a relatively high injection well to inspector ratio the review team determined that the state's inspection program is providing good protection to USDWs. This effectiveness results in large part because of the focus on matters which can provide the greatest degree of USDW protection including attention to water flows, well construction, plugging and abandonment, mechanical integrity testing, citizen complaints related to pollution and illegal activities.

The procedures used in Oklahoma to establish mechanical integrity are protective of USDWs. The state utilizes annulus pressure tests and cement record review as the predominant means for determining mechanical integrity. A major effort has been underway to complete the required pressure testing for pre-primacy wells.

A variety of multi-level enforcement tools are available to achieve compliance, from simple field inspector notification through formal hearings and fines. The review team concluded that the compliance and enforcement portion of the Oklahoma UIC program is structured and implemented in a manner that is more than adequate for protection of USDWs.

At the time of the on-site UIC program review the data management system was being modified. The UIC Department has now completed an extensive effort to computerize essential files and records. The computer system is used to track permitting, mechanical integrity test scheduling and reporting, inspection documentation, compliance monitoring and EPA reporting. The review team concluded that the data management system being used at the time of the review would facilitate the protection of USDWs and that the proposed data management system enhancements, now in place, would substantially enhance the protection of USDWs.

The Oklahoma public outreach program is designed to reach and inform the regulated community and interest groups as well persons directly affected by any particular permit. The review team found this portion of the Oklahoma program to be appropriate and lend itself to the protection of USDWs.

The Kansas Corporation Commission Conservation Division UIC Program

The sixth state UIC program review was conducted in Wichita, in January, 1990. The Conservation Division of the Kansas Corporation has regulatory authority for Class II injection wells in Kansas. The Division is

responsible for UIC permitting, file reviews, general data management, formal compliance, hearings, program administration and field inspections.

UIC Unit procedures, permit application reviews, and data resources available are sufficient to assure that injection well permit applications receive proper evaluation. The UIC staff is knowledgeable and experienced. Minor concerns were expressed relative to financial assurance, the lack of specific detail in the required public notification of proposed injection wells and the lack of clearly defined standards for minimum cement thickness above the injection zone. Overall, the review team determined that the permitting portion of the Kansas UIC program is being conducted and supported in a manner protective of USDWs.

Field inspections are performed by 40 state inspectors operating from four district offices. Inspectors are well qualified with a minimum of two years of related field experience required. Inspection priorities are logical with contamination events as the highest priority. The review team concluded that this portion of the Kansas program is providing good to excellent protection of USDWs.

Kansas primarily uses positive pressure tests, positive annulus pressure monitoring and cement record evaluations for the demonstration of mechanical integrity. Mechanical integrity test notification and follow up procedures are clearly defined and assure all wells are tested. A minor concern was expressed that a new mechanical integrity test after a workover is not a requirement unless the packer is reset at a different depth. With only the expressed concern, the review team concluded that the Kansas mechanical integrity testing program provides an excellent degree of USDW protection.

The Division use a variety of both formal and informal enforcement actions to maintain injection well compliance. The compliance and enforcement program operated by the Division is sufficient to enforce compliance with UIC permit conditions and state rules and provide USDW protection.

Standard plugging requirements are designed to isolate and protect all oil, gas, fresh water and USDWs. Cased hole pluggings are a high priority for field inspector witnessing. The plugging portion of the Kansas UIC program was determined to be conducted in a manner that is effective in protecting USDWs.

The Division effectively uses a combination of manual and computerized systems for managing data, program tracking and enforcement. The review team concluded that the Division data management system is facilitating and enhancing the protection of USDWs.

The Division conducts an appropriate public outreach program which keeps the regulated community and the general public informed. This program area is being adequately carried out to facilitate protection of USDWs.

Conclusions

Although the states may operate their individual UIC programs and program elements differently, the overall consensus for the six state reviews completed to date is that, with only minor exceptions, the states are maintaining efforts to effectively protect USDWs from contamination by Class II injection wells. Many of the state programs take different approaches to permitting, inspections, mechanical integrity testing and enforcement, however, each state program ultimately provides the framework for USDW protection.

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Simple Injectivity Test and Monitoring Plan for Brine Disposal Wells Operating By Gravity Flow

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Introduction

The injection of produced brine waste-water from oil and gas operations into disposal wells in the United States requires a permit from the Underground Injection Control (UIC) Program of the U.S. Environmental Protection Agency (EPA). In the application for a UIC permit, oil and gas operators must demonstrate proper construction of the injection well and any nearby wells, termed area of review (AOR) wells, that will be affected by the injection. Proper well construction protects any underground source of drinking water (USDW) from contamination by the injected brine. If the injection well or AOR wells are improperly constructed or if any AOR wells have been improperly plugged and abandoned, then corrective action requirements to remediate these problems are necessary prior to EPA injection authorization.

This paper assumes that the injection well itself is properly constructed but that the AOR wells are in need of corrective action. The usual cause of corrective action requirements in AOR wells is inadequate casing or cementing in production wells and improperly placed plugs in abandoned wells. AOR wells must be constructed or abandoned so that there are no pathways for migration of brine into a USDW.

Implementation of corrective action requirements by an operator for a UIC permit might result in new casing and cement for production wells, plugging and abandonment of production wells, and even the replugging of previously abandoned wells. The expense involved for any of this work is often prohibitive for operators of stripper wells, these are wells that produce less than ten barrels of oil per day (BOPD). Since brine disposal options other than underground injection are limited, many stripper well operators are forced to either shut-in production or dispose of their brine by illegal underground injection or surface dumping. Shut-in production may result in the loss of the mineral lease if there is a non-production clause in the lease agreement while illegal disposal may result in degraded surface water and/or USDW's.

Another problem arises should the AOR for the injection well extend on to another operator's lease where there are wells in need of corrective action. In this case the operator is faced with two additional problems, the expense of corrective action on another operator's lease and permission to access the other lease in the first place. UIC regulations cannot force the second operator to allow access to his lease for well workovers by the operator seeking approval for the injection well. If the corrective action in this case cannot be performed, then the UIC permit cannot be issued.

The objective of the UIC Program is to protect USDW's while having as minimal an economic impact on the oil and gas industry as possible. Stripper well production in the conterminous United States during 1988 was 1.2 million BOPD from 454,150 wells (1). This amounted to 24% of the lower 48 states's onshore production. As an critical energy source for this nations economy, it is important to maintain this production while at the same time preserving water quality in the nations USDW's.

As an alternative to expensive corrective action requirements for AOR wells, this paper presents a cost-effective, easy-to-use injectivity test and monitoring plan for brine disposal wells operating by gravity flow which can be used to demonstrate that no endangerment to USDW's exists when applying for a UIC permit with EPA Region IV (Atlanta, Georgia). The test is also less expensive and easier to implement than multiple well pressure transient tests, especially when the porosity in the injection zone is very heterogeneous which makes selection of appropriate observation wells difficult.

Injectivity Test and Monitoring Plan Criteria

The gravity flow injectivity test and monitoring plan have been incorporated into UIC permits issued by EPA Region IV. Injectivity tests have been successfully completed as conditions to the permits and routine monitoring operations have commenced. As a result, stripper well operators who were shut-in because of expensive corrective action requirements have been able to restart production on their leases.

The gravity flow injectivity test and monitoring plan are performed on the injection well itself and are applicable only to disposal wells that operate under gravity flow conditions. This precludes disposal wells and enhanced recovery wells that operate with a positive pressure at the wellhead. The test was developed where the use of separate observation wells was impractical, however, the test could be used for any gravity flow injector under the appropriate conditions.

The injection well for which the test was developed injects into a dolomite where the porosity is very heterogeneous. The effects from injection on an AOR well would be greatest if the AOR well were linked by a highly porous zone directly to the injection well. The injectivity test therefore assumes a worst case scenario in which the greatest possible effect on an AOR well from injection would result in AOR well fluid levels equal to the operating

fluid level in the injection well. If the operating fluid level within the injection well can be demonstrated and maintained at a safe level below the lowermost USDW, then corrective action on AOR wells can be waived provided long term operating fluid level monitoring is performed.

EPA Region IV has been using a depth of 100 feet below the lowermost USDW as the critical depth above which the operating fluid level in the injection well should not rise. This is used as a safety factor for changes in fluid levels between monitoring events and also for variables such as depth variation for stratigraphic horizons between AOR wells and differences in static fluid levels between AOR wells. The gravity flow injectivity test is not applicable to injection wells with a limited geologic section between the lowermost USDW and the injection zone since this safety factor cannot be incorporated in the test. Also, the static fluid levels in these wells are probably too high to begin with.

Prior to the injectivity test, the static fluid level in the injection well should be recorded. If the static fluid level in the injection well is above the highest safe operating level, then the well obviously does not qualify for using the injectivity test. To ensure the static level is similar within the AOR, the static fluid level should be measured in at least one other well. Static fluid levels in the injection and AOR wells should be similar, but if they are not the critical depth mentioned above can be adjusted. If the wells to be measured have been active, they should be shut-in long enough to obtain static conditions.

Operating conditions regulated by a UIC permit include injection pressure, fluid volume, and injection rate. Injection pressure is limited to gravity flow. Fluid volume is the number of barrels of brine to be disposed of daily. Injection rate determines the period in the day over which the fluid volume is disposed. The injection rate that works best is barrels per hour. This rate ensures relatively even disposal over the course of a day and can be accomplished by the operator staggering the timers on production well pumps.

To perform the injectivity test, the operator must have a sufficient volume of water available to demonstrate that the volume of brine to be produced on his lease can be safely reinjected. This could be accomplished by obtaining an appropriate-sized stock tank and filling it with either fresh or produced water; or, it could be accomplished by using a water truck for a supply at the site. Using produced water actually allows the operator to perform the test without disrupting production operations.

The gravity flow injectivity test uses the same well for both injection and monitoring. Brine is injected through tubing in the well casing. This isolates the injectate from the tubing/casing annulus. Fluid levels are then recorded through the tubing/casing annulus. Packers are prohibited in the well so that there is an unrestricted fluid level in the annulus. Centralizers on the tubing help keep the tubing centered in the casing but must be placed below the operating fluid level in order not to obstruct the operation of the water level indicator.

A good fluid level recording device is a battery-powered water level indicator. The indicator consists of a probe and cable which are attached to a reel. Fluid levels are recorded by hand-lowering the probe and cable through the wellhead and down the tubing/casing annulus until the operating fluid level is reached or at least until a predetermined safe distance below the lowermost USDW has been reached. The isolated tubing/casing annulus prevents a premature fluid level reading from the water level indicator.

The expense of the water level indicator is minimal (~$500 to $1200) when compared to the expense of corrective action requirements. The indicator is good for depths up to 1000 feet which is the maximum cable length. For cases where deeper readings are needed, an echo meter will work well but the cost (~$10,000) is more prohibitive for stripper well operators. This device is attached to the wellhead and employs an energy source consisting of compressed gas or a blackpowder charge. The echo meter records the two-way travel time of sonic waves reflecting off the fluid level's surface. The two-way travel time is then converted to depth.

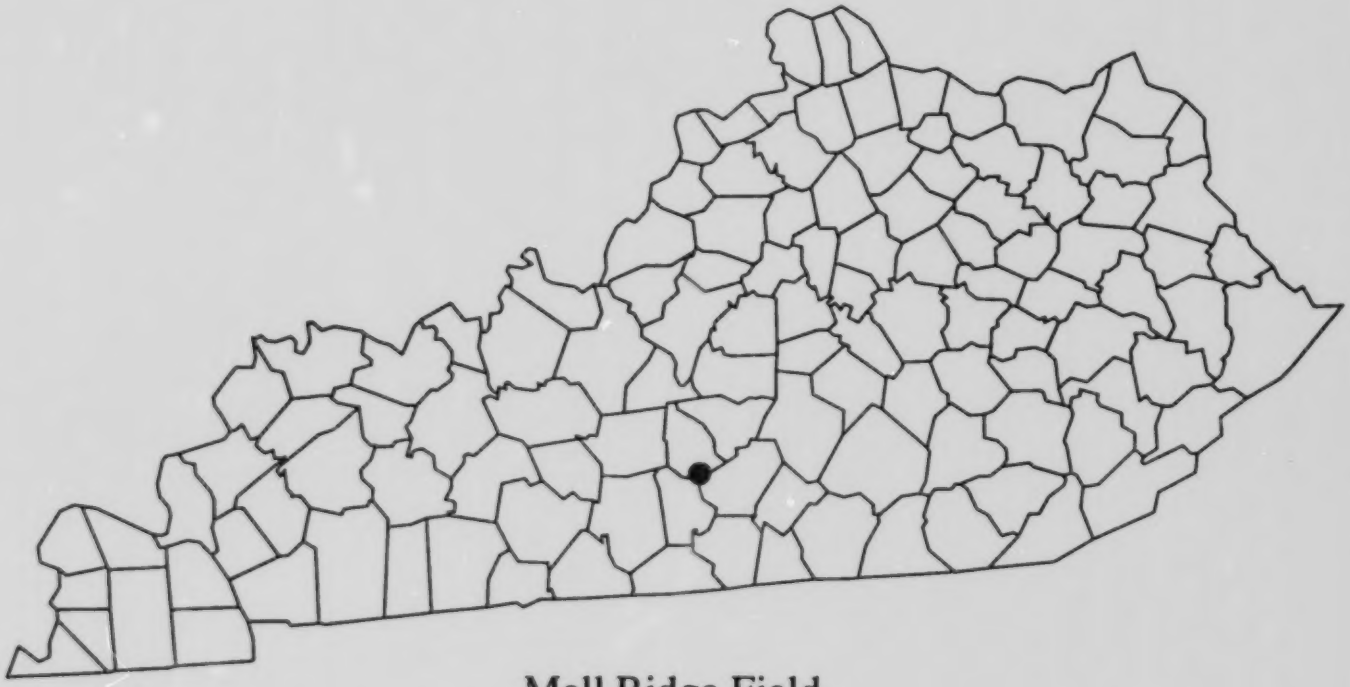
A simple schedule for performing the injectivity test might consist of the following: an hourly fluid level reading for six to eight hours during the first day, a daily reading the remainder of the first week, and a weekly reading during the remainder of the month. If the readings indicate that the operating fluid level is at a safe distance below the lowermost USDW, then the injection well is considered to have successfully completed the injectivity test. Further fluid level recordings are then required under routine monitoring requirements incorporated in the UIC permit. Routine monitoring frequency for operating fluid levels would normally be performed on a weekly or monthly basis. This monitoring can be performed concurrently with other monitoring activities required in the UIC permit.

Case Study

The injectivity test was developed for an injection well located in Mell Ridge Field, Green County, Kentucky (Figure 1). The operator had shut-in production on his lease since early 1988 due to expensive corrective action requirements needed on AOR wells. Especially problematic was the fact that an unplugged abandoned well in the AOR was within another operator's lease where access was denied.

Oil production from the Mell Ridge Ridge Field occurs from porosity zones within the Cambrian Knox dolomite. These porosity zones occur irregularly within the area and are difficult to predict. From the operator's experience of production history in the field, he could establish no interconnectability of the porosity zones between the wells. As a consequence, the use of a multiple well pressure transient test with separate injection and observation wells was impractical and expensive. All wells would have to be equipped with expensive monitoring equipment including the well the operator could not get access to. Because of the irregular porosity, simply monitoring a few selected AOR wells and demonstrating no effect from injection would not prove that other AOR wells were not being adversely effected by the injection.

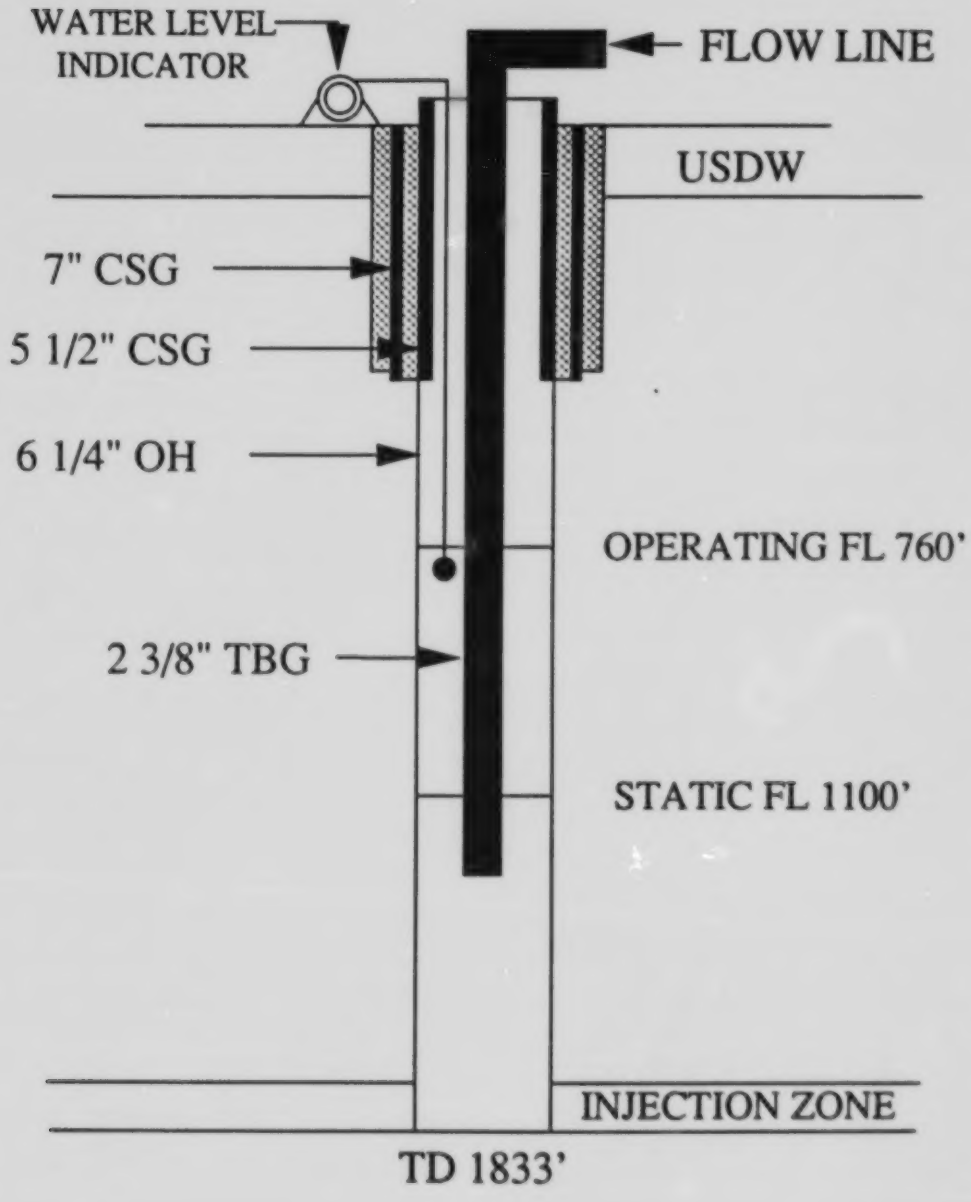
Figure 1



Mell Ridge Field
Green County, Kentucky

Figure 2

LEMUEL ROBERTSON #6-A
GREEN COUNTY, KENTUCKY



The injection well for this study is the Lemuel Robertson #6-A well (Figure 2). This well has a total depth of 1833 feet from surface with 5 1/2 inch casing set at 410 feet from surface. Internal casing diameter is approximately 5 inches. There is 1250 feet of 2 3/8 inch tubing with 2 7/8 inch couplings within the wellbore. This leaves an annular space between the casing and the tubing couplings of 1 1/16 inches. The probe diameter of the water level indicator is 3/8 inch so there was limited space to lower the probe down the annulus. The open hole below the 5 1/2 inch casing is 6 1/4 inches in diameter. This leaves a tubing/wellbore annulus of 1 11/16 inches.

The test had originally been devised for the 2 3/8 inch tubing inside of 7 inch casing which had been set at 406 feet below surface, but leaks detected in the 7 inch casing necessitated installation of the 5 1/2 inch casing. The injectivity test was attempted even with the limited casing/tubing annulus because the operator was faced with the imminent loss of his lease due to non-production for over a two year period.

The lowermost USDW in the injection well was determined to be the base of the Mississippian Salem-Warsaw limestone (undifferentiated) which is at a depth of 125 feet from surface. The highest allowable operating fluid level within the injection well was set 100 feet below the USDW at a depth of 225 feet from surface. The static fluid level in the Lemuel Robertson #6-A well was measured by bailer at 1100 feet below surface (-160 feet, 1927 North American datum). The static fluid level measured in an AOR well, Lemuel Robertson #8, was 1060 feet below surface (-185 feet, 1927 North American datum).

The operator used a 210 barrel tank as his water supply for the injectivity test. The operator was allowed to use produced brine to fill the stock tank, resuming production just prior to the test. Initial production from recommencing operations on his lease was 15 BOPD from four wells. To maintain a constant rate and supply of water, the operator staggered pump timers on the four production wells.

The injection rate for the injectivity test varied between 9 and 10 barrels of brine per hour. During the first week of the test, the operating fluid level as measured in the casing/tubing annulus by a water level indicator was between 760 and 769 feet below surface. This was over 500 feet below the predetermined safe operating level of 225 feet below surface. As a comparison to the operating fluid level, a water level reading was taken within the tubing immediately after stopping injection and disconnecting the flow line. This reading showed that the water level had already fallen to 911 feet below surface. While not critical in this case, this illustrates why it is important to measure the operating fluid level.

At the end of the first week of the injectivity test, the cable of the water level indicator became stuck in the limited casing/tubing annulus and separated. The operator continued injection and at the end of the second week pulled tubing in an attempt to retrieve the indicator. The water level

indicator was retrieved from the end of the tubing and the water line on the tubing indicated the operating fluid level had fallen to about 950 feet below surface. The operator completed the test with a back-up 300 foot long water level indicator. This did not allow the actual operating fluid level to be recorded but did ensure that it did not rise above 225 feet below surface for the remainder of the test.

Smaller tubing possibly can eliminate the problem of a restricted casing/tubing annulus if disposal volumes can be maintained. Another possible alternative would be to inject through the casing/tubing annulus and monitor through the tubing. This method may be attempted with a couple wells currently being reviewed for UIC permits by EPA Region IV. However, EPA Region IV requires new brine disposal wells to inject through tubing during routine operations. This presents a problem after the test in that routine operating fluid level monitoring is required on at least a monthly basis. For each monitoring event, disposal operations would need to be shut down to switch the flow line from the tubing to the casing/tubing annulus and then the operating fluid level would need to be re-established.

Summary

The gravity flow injectivity test and monitoring plan allows for injection through tubing and monitoring through the casing/tubing annulus of the same well. The test is only applicable to injection wells that operate by gravity flow.

The injectivity test assumes a worst case scenario in which the fluid levels in AOR wells are assumed to be as high as the operating fluid level in the injection well. If the operating fluid level in the injection well is determined to be at a safe level below the lowermost USDW then brine injection is allowable even if AOR wells are not properly constructed or plugged and abandoned. The test allows operators to avoid expensive corrective action requirements on AOR wells while also protecting USDW's. As a consequence, some operators of stripper wells who where shut-in because of the expense of corrective action requirements can now economically produce oil and dispose of their brine in an environmentally safe manner.

The gravity flow injectivity test is less expensive and complicated than a multiple well pressure transient test with separate injection and observation wells. The gravity flow test also allows for routine production operations to continue during the test.

While this test was developed for a carbonate reservoir with unpredictable porosity zones, the test could also work for clastic reservoirs especially if an extra well was not available for monitoring purposes. Also, while this test was developed for EPA permits to protect USDW's, it could be used anywhere there is stripper well production with gravity flow disposal.

Reference

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SOLIDIFICATION OF RESIDUAL WASTE PITS AS AN ALTERNATE DISPOSAL PRACTICE IN PENNSYLVANIA

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Introduction

Regulations adopted in 1989 by the Pennsylvania Department of Environmental Resources (the Department) require that oil and gas operators contain pollutional substances and wastes from their activities in tanks or in pits constructed according to standards which protect ground water. If the pits are also to be used for waste disposal, additional ground water protection standards apply. An operator wishing to apply an alternate practice for the disposal of wastes may request approval from the Department to use the practice. Several operators have explored solidification of pit contents as an alternate waste disposal practice. This paper summarizes some of those efforts.

Summary of Requirements

Pennsylvania regulations establishing environmental protection performance standards for oil and gas well operations are found at 25 Pa. Code §§ 78.51 - 78.63. These regulations contain a general provision that the operator must control and dispose of fluids, residual waste and drill cuttings, including drilling fluids, drilling muds, stimulation fluids, well servicing fluids, oil, and production fluids, in a manner that prevents pollution of ground or surface waters. The control and disposal procedures are to be contained in a plan, developed and implemented by the operator, which is subject to review and approval by the state regulatory agency, the Department of Environmental Resources.

Pollutional substances and wastes from well drilling, alteration or completion are to be contained in tanks or pits. Such tanks or pits must meet requirements relating to capacity, freeboard, and structural stability. Pits must also meet standards for impermeability, construction, and depth to groundwater. Site reclamation, including tank removal or pit closure, is to occur within nine months of completion of drilling. The free liquid fraction

is to be removed and disposed in an approved manner. The solid residual waste remaining is to be buried on site or applied to the land surface according to prescribed standards.

Pits used for the disposal of residual waste must satisfy numerous restrictions designed for the protection of ground water. Only wastes generated at the well site may be disposed in the pit. The well must be properly permitted and bonded. The pit must be at least 200 feet from an existing building, at least 100 feet from a stream or wetland, and at least 200 feet from a water supply. The bottom of the pit must be at least 20 inches above the seasonal high ground water table. The pit must be structurally sound and impermeable. The pit must be lined with a synthetic flexible liner that is at least 30 mils thick. The liner material must satisfy the compatibility of EPA Method 9090 (1). The pit must be constructed and graded so that the liner will not be torn or punctured during use. If the pit bottom or sides consist of any material that may cause the liner to fail and leak, a six-inch subbase material must be installed over the pit area to protect the liner. Prior to use, the liner must be inspected for damage, and repaired if necessary. During closure, the free liquid fraction must be removed and the liner folded over or an additional liner added to completely cover the waste. Puncturing or perforating the liner is prohibited. The pit must be backfilled to at least 18 inches over the top of the liner, and the surface area must be graded to prevent ponding and be revegetated.

The regulations further specify reporting requirements and limitations to wastes which may be disposed in this manner. The waste limitations preclude the disposal of hazardous wastes at well sites.

Operators may request approval to use solidifiers or other alternate practices for residual waste disposal from the Department. The request must demonstrate that the practice provides equivalent or superior ground water protection to the standards contained in the regulations.

Solidification Proposals

Since the regulations went into effect, gas well operators have expressed the most concern and interest in obtaining an approved method for solidifying wastes. The typical gas well being drilled in the areas requesting solidification of pit wastes are approximately 5000 feet deep and are drilled using air rotary drilling systems. Some of these systems require the use of drilling muds and other additives to bring the well to completion.

Concentrations of parameters normally seen in the wastes from these wells were high enough for the Department to be concerned with ground water protection when writing the new regulations. Thus, the standards imposed in the regulations were meant to address those concerns.

Several operators have requested approval from the Department to use various products or materials for pit solidification or stabilization. The reasons for these requests varied.

After removal of the free liquid fraction of pit wastes, the remaining pit contents usually still contain approximately 30% water. Operators found that backfilling these residual waste pits often did not demonstrate stability compatible with adjacent land areas. This would result in complaints from surface owners, particularly those engaged in farming. Soft spots in farm fields were not acceptable.

In some gas fields, operators were not able to land apply residual wastes because of the high salt content. The use of pits then became the disposal method of choice. But due to the unacceptability of soft spots in fields, the availability of using pits for disposal at these locations became limited.

Also, operators were concerned with the 30 mil liner thickness requirement for disposal pits. They felt that 30 mil liners would cause operational problems because of the liner weight and the additional equipment and manpower that would be necessary to properly install the liners. They also believed the liners were too expensive for routine operations and were not justified in all instances.

After reviewing these items, operators began to look toward solidification as a possible answer to their concerns. The addition of a solidifier or stabilizer would remedy the soft spots in fields. They also felt that if proper solidification could be accomplished, pollutional constituents in the residual waste would be bound in the solidifier matrix, and equivalent ground water protection would be afforded. This could lead to a Department approval of the use of an alternate liner system.

Thus, requests for solidification or stabilization of pit contents were submitted to the Department for approval. Pit solidifications of wastes from oil and gas exploration and development had been completed previously in Pennsylvania and in other states. However, an apparent lack of available data existed to evaluate the effectiveness of various solidifiers in stabilizing the waste, the ratio of waste material to solidifier necessary, the methods by which adequate mixing could be accomplished, and the characteristics of leachate expected from the solidified mixture. Literature searches and contacts with other states in the region were unfruitful. The need to generate data through demonstration projects was evident.

Demonstration Projects

In developing a solidification process proposal, operators considered systems that would provide ground water protection, achieve land stabilization, be workable at the well site, be able to overcome the operational constraints of

handling a 30 mil liner, and be cost effective. Originally, two proposals were explored.

The first proposal involved using a solidifier and pit content mixture that would be binding or impermeable enough to prevent the leaching of potential pollutants from the solidified mass. This mixture would also be hard enough to provide pit stability. In this case, to assure complete mixing of the wastes with the solidifier, the liner would be destroyed during the mixing activity. Since solidification would prevent the leaching of pollutants to the ground water system, a thinner liner could be used for protection up to the time of solidification.

The second proposal involved maintaining the integrity of the pit liner to provide ground water protection, while utilizing the solidification process to provide physical stability to the pit contents.

Following discussions regarding which system was best suited to accomplish the goals of the industry and the Department, several sites were proposed as demonstration projects.

Proposals for approvals using the first concept described above were submitted by four operators. The use of solidification mixtures from three servicing companies were included in the proposals. One servicing company had been performing bench tests on pit contents and solidifier mixes to determine the proper amounts of ingredients for the solidifiers and the appropriate waste to solidifier ratio to accomplish the goal of providing ground water protection. After consideration of this bench testing, original approval was granted by the Department to utilize the solidification process with a waste to solidifier ratio of 10:1 for the demonstration projects.

The approvals for the use of the solidification process were granted subject to several conditions. One of the major conditions was that each operator was required to select a site that would be suitable to be used for ground water monitoring. On this site, the ground water monitoring system would be installed prior to the start of drilling the oil or gas well to obtain predrilling samples of the existing ground water quality. Then, when the pit was ready to be closed, samples of the solid fraction of the residual waste after mixing with the solidification mixture would be tested and the ground water would be tested for effects from any leaching from the pits. Ground water monitoring would continue for the months following solidification.

For the solid fraction mixture, the parameters evaluated would be: by EP toxicity test (2) - arsenic, barium, cadmium, chromium (total), and lead; and by ASTM A leachate test (3) - chloride, sodium, calcium, magnesium, bromide, MBAS, sulfates, and strontium. For the ground water, the following parameters would be evaluated: arsenic, bromide, barium, calcium, chloride, chromium (total), copper, magnesium, MBAS, iron (total), oil & grease, lead, pH, nickel, sodium, strontium, sulfates, specific conductance, and total dissolved solids.

Other conditions of approval included providing at least 48-hour notice to the Department prior to the date of the pit solidification, providing a description of the consistency of the mixed pit material after 24 and 48 hours setting time, using a minimum 10 mil thick liner, and submitting a standard report to the Department within 30 days of pit closure or with the well completion report.

One trade association in Pennsylvania has recently proposed a demonstration project involving a system that would be utilized to provide pit stability within a 10 mil liner. This proposal intends to protect the liner system, rather than destroy it during mixing, while using a solidifier material that would provide extensive savings to the industry.

Results

Immediately following the effective date of the Department's regulations, a major demand was put forth by the industry to utilize pit solidification for disposal of residual waste in pits. Several problems became evident rather quickly.

As the first sites were being solidified, operators considered and tried different methods of adding the solidifier mix to the pits and of mixing the solidifier with the pit contents. The initial method used to add the mix to the pits was for a worker to hold the discharge hose and manually direct the mix to different areas of the pit. This method was extremely dusty (thus considered hazardous to the health of the worker) and was not adequate in achieving a uniform distribution of the solidifier over the pit.

Following the addition of the mix, a trackhoe operator with a toothed backhoe bucket would incorporate the mix into the pit. This method of mixing was time consuming because the operator had to load the bucket at the edges of the pit where the solidifier was placed and move this drier material to the wetter portions of the pit to achieve complete mixing.

Pit construction methods also caused some problems. Some pits had nearly vertical, jagged sideslopes or did not have sufficient subbase to protect the liner prior to solidification. Some pits were constructed deep and narrow which did not allow adequate room for a trackhoe arm to mix properly. Other pits were constructed in such a way that the middle of the pit could not be reached for mixing.

Also, the setup time of the solidified pits varied considerably. Some pits took 2 or more days to harden. Other pits were able to be walked on within 6 to 8 hours of the completion of the solidification process. The reasons for these extremes appeared to be the result of several items including: the inability to accurately estimate pit volumes in order to calculate the

required waste to mix ratio; the amount of free liquid remaining in the waste following decantation of the liquid fraction; the type of well and the resulting drilling system used; and the over-ordering of solidification material by some operators to be certain of hardening.

Several of these problems were easily resolved through the cooperation of the operators and their willingness to complete the process in the proper fashion and to make the system work. Within the period of a few weeks, operators devised a mixing device constructed of metal tubing resembling a "slotted spatula" which could be attached to the trackhoe bucket. This device could then be moved back and forth through the pit contents to assist in more complete mixing. At about this same time, operators decided to attach the discharge hose from the solidifier truck onto this mixing device which would allow the mix material to be added anywhere within the reach of the trackhoe.

Pit construction methods also were changed to protect the liner by making the pit sideslopes flatter and providing subbase material, and to make the pits easily accessible for the trackhoe to operate properly and provide complete mixing.

A solution to the problem of determining the proper time for closure was not as easily found. Establishment of performance standards appeared to be a solution to obtain a required hardness or other measure to demonstrate the time for closure. But since environmental protection was one of the major goals of the demonstration projects, a decision on what to include as performance standards could not be made until results from the ground water monitoring could be evaluated.

Regarding the testing being performed, EP toxicity testing was required to be performed on the solidifiers from each servicing company. Thus far, none of the solidifier material samples have been found to exhibit characteristics of EP toxicity. The highest value reported for any of the tested parameters in the solidifiers was for lead. The lead concentration of one solidifier was reported at 13.2% of the maximum allowable concentration. The only other parameter reported at a value greater than 10% of the maximum allowable concentration was for total chromium. Again, one solidifier had a chromium concentration reported at 12% of the maximum. The majority of the reported values were 1% or less of the maximum allowable concentration.

Once an operator received approval from the Department to utilize the solidifier from a particular servicing company, the operator had thirty days to submit EP toxicity and ASTM A leachate test results of the combined waste and solidifier mixture to the Department. The EP toxicity testing was requested to obtain information on whether any reactions or compounds formed from the mixing of the waste and the solidifier may cause environmental harm or degradation. The results of the EP toxicity testing indicated that the solidifier and waste combinations did not exhibit characteristics of EP toxicity. Only one parameter from one pit had a reported value higher than 10% of the maximum allowable concentration. Total chromium was reported at

12.9% of the maximum in this instance. A few of the values were reported between 1% and 10% of the maximum, but most were 1% or less.

The ASTM A leachate testing was requested to obtain concentrations of parameters in the residual waste that would normally be expected to leach. These parameters would serve as indicators of potential pollution to the ground water system if they would begin to appear in elevated concentrations in the monitoring samples.

At the four sites selected for ground water monitoring, monitoring wells were drilled down to the interception with the ground water table. At three of the four sites, two monitoring wells were drilled. All wells were placed downgradient, 5 to 10 feet from the edge of the pit, at a location where Department hydrogeologists believed effects from any leaching would be observed. On the fourth site only one downgradient monitoring well was drilled. Following the completion of the monitoring wells, samples were taken of the ground water for background information. Samples were also taken from the wells on the days that solidification took place. Following the pit solidifications, samples were taken from the wells on a monthly basis for three months.

Because the study is ongoing, only a limited number of monitoring samples have been taken to date. Results obtained at one of the sites indicated increasingly elevated results in arsenic, iron, copper and barium, although visible increases in the indicator parameters were not observed. Samples from one other site indicated a slight increase in the results of iron. The other two sites have not indicate elevated concentrations of any of the parameters tested.

Conclusion

The purpose of this paper is to provide an introduction to the demonstration projects performed in Pennsylvania utilizing solidification as a method of protecting the ground water. Insufficient data exists at this time from the monitoring wells to make a determination of whether the systems described have accomplished the goals. Samples will continue to be taken at these monitoring locations to observe if more time is required for any leached constituents to reach the ground water tables and if any of the elevated results in parameter concentrations can be attributed to season variations.

Tabulated results of all of the sampling completed will be made available upon request. A report will be given at a later date regarding the determinations of the successes or failures of the projects.

As pit solidifications continue, further improvement on the individual phases of the process should be pursued, for example, if a better mixing method can be developed or if a lower waste to solidifier ratio is necessary.

One other concern that has surfaced in recent months is whether operators can satisfactorily complete the solidification process during the winter months. Temperatures in Pennsylvania typically can be at or below zero degrees Fahrenheit in the winter. Freezing temperatures cause problems in dealing with the free liquid portion of the wastes and affect the hardening or stiffening properties of solidifiers. Some servicing companies have begun work to create a solidifier mixture that will alleviate this problem.

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STATISTICAL ASSESSMENT OF FIELD SAMPLING PROJECT DATA ON PETROLEUM EXPLORATION AND PRODUCTION WASTES

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Introduction

As part of the study mandated by Section 8002(m) of the 1980 Amendments to the Resource Conservation and Recovery Act, the U.S. Environmental Protection Agency (EPA) sampled the wastewaters of a diverse group of Petroleum Exploration and Production facilities across the U.S. EPA undertook the Field Sampling Project to develop statistically representative data that would describe the range and concentrations of waste constituents from drilling and production operations nationwide [1]. SRA Technologies, Inc. was tasked by EPA's Office of Solid Waste (OSW) only with evaluating the statistical validity of the resulting database; while, evaluation of the quality assurance/quality control aspects of the field sampling and laboratory analysis were assigned to others by EPA. Thus, SRA's study had three main objectives: (1) to independently assess, from a statistical standpoint, the strengths and limitations of the data then available from the EPA Field Sampling Project; (2) to investigate issues such as weighting and the treatment of censored data; and (3) to make recommendations about additional sampling--if required--to augment the current Field Sampling Project database.

There were six major conclusions reached in this statistical assessment, among them, the following standout: the EPA study is consistent with the similar American Petroleum Institute (API) study; more sampling would be advisable to improve representativeness; and many of the inorganic substances had waste liquid concentrations that exceeded drinking water standards. The study noted that all of the production and drilling sites had at least one key analyte that exceeded water quality standards. In addition, for many of the key analytes, substantial proportions of the sites exceeded 10 times the water quality standards and in some instances sites exceeded the standards by 1,000 times.

Project Background

The facilities sampled in the Field Sampling Project included 21 production sites, 22 drilling sites, 5 central pits, and 2 centralized treatment facilities; these units are listed in Table 1, which identifies the site type of the facility and lists the geographic basins in which they are located. Table 1 also lists similar information from a number of Alaskan sites units that were added at a later date to the Field Sampling Project database for study purposes. The states were clustered in eleven zones based on physiographic similarity and statistically "stratified" samples were taken of production endpoint liquids, drilling pit liquids, and drilling pit solids. Most such samples were taken from randomly selected sites, but some--and the few samples taken from central pits and centralized treatment facilities--were taken from non-randomly selected sites. Samples of drilling pit solids were chemically analyzed both directly and by the Toxicity Characteristic Leachate Procedure (TCLP) test. The locations of

TABLE 1. List of Basins and Sites Sampled (Lower 48 States) *a*

Site	Type *b*	Basin	Site	Type	Basin
1	D,P	Anardrko Basin	27		Llano Basin
2	D,P,CT	Appalachian Basin	28		Marfa Basin
3	D,P,CP	Arkoma Basin	29	2D,P	Michigan Basin
4		Black Warrior Basin	30		Mississippi Basin
5		Central Nebraska Basin	31		Mississippi Salt Dome Basin
6		Central Oklahoma Platform	32	D,P	Paradox Basin
7		Cincinnati Dome	33	P	Permian Basin
8		Coast Range Basin	34		Piceance Basin
9	CP *c*	Colorado North Basin	35	D,P	Powder River Basin
10		Crazy Mountain Basin	36		Raton Basin
11	P,CP	Dalhart Basin	37	D,P	San Joaquin Basin
12		Delaware Basin	38	P,CP	San Juan Basin
13		Denver Basin	39		San Luis Basin
14	D,P	Dodge City Embayment	40		Snake River Downwrap
15		East Texas Salt Basin	41		South Alberta Basin
16		Eocene Basin	42		South Florida Embayment
17	D	Porrest City Basin	43		South Park Basin
18		Great Basin	44		South Texas Salt
19	D,CP	Green River Basin	45		Tucumcari Basin
20	2D,5P	Gulf Coast Basin	46	D,P	Tyler Basin
21		Hardeman Hollis Basin	47	D	Unita Basin
22		Hanna Basin	48	D	Ventura Basin
23		Hugoton Embayment	49	D,P	Washakie Basin
24	D,P	Illinois Basin	50	D	Williston Basin
25		Laramie Basin	51		Wind River Basin
26		Las Vegas Basin	52		Wyoming Big Horn Basin

TABLE 1. List of Basins and Sites Sampled (Alaska)

1		Bethel Basin	5		Koyukuk Basin
2	D,P,CT	Cook Inlet Basin	6	2D,P	North Slope Basin
3		Copper River Basin	7		Yukon Kandik Basin
4		Galna Basin			

Key for Site Types: D=Drilling, P=Production, CP=Central Pit, CT=Central Treatment

a. U.S. EPA, April 30, 1987 [2]
b. U.S. EPA, January 31, 1987 [1]
c. Landes, 1970, pp. 380. 385 [3]

the basins and units sampled and the zones into which they have been placed for the purposes of this study are also shown in Figure 1.

Statistical Analyses

The evaluation of statistical validity addressed: sampling plan design and data collection; representativeness of the samples vis-a-vis the petroleum bearing basins; weighting of data to reflect wastewater flows from the various basins; and precision of the resulting data. A comparison was also made with data from a parallel survey and study by the API.

The evaluation focused on a group of 11 inorganic and 5 organic "key" pollutants that were selected based primarily on (1) expected presence in a large proportion of the samples, (2) inherent toxicity, and (3) significantly high concentrations. The principal selection procedure used is one developed by EPA/OSW for use at "Superfund" sites [4].

The substances selected as key pollutants using the EPA/OSW procedure (and the number of times they were analyzed for and detected) were:

Inorganics				Organics	
Barium	120/115	Cadmium	120/52	Toluene	112/61
Fluoride	81/80	Lead	120/46	Benzene	112/44
Chromium	120/68	Arsenic	120/36	2-Butanone ('MEK')	112/31
Nickel	120/60			Phenol	113/25
				Phenanthrene	113/21

Four additional substances were also included as key pollutants based mainly on their known potential to damage vegetation. These substances were antimony, boron, chloride and sodium.

Substances passed over as key pollutants using the EPA/OSW procedure (and the number of times they were analyzed for and detected) were:

Organics			
bis-(2-Ethylhexyl) Phthalate	113/59	Bromodichloromethane	112/4
Naphthalene	113/52	Pentachlorophenol	108/3
Ethylbenzene	112/39	Anthracene	113/0
1,1,2-Trichloroethane	112/6		

FIGURE 1. Map of Petroleum Basin Locations

Varying proportions of the data sets for the different analytes/pollutants are listed as "below the limit of detection". These are also termed "censored" values. The detection limit is a function of both the sensitivity of the laboratory analytical technique and of the presence of interfering substances in the sample matrix. It is important to recognize that the notation "below the limit of detection" is an indication that the field sampling and laboratory analysis were inconclusive; it could indicate that the analyte is present at some concentration below the detection limit, or that the analyte is absent altogether. When the detection limits are lower than potential regulatory limits, interpreting the results is relatively simple. However, if the proportion of censored values is high, the manner in which censored data are treated can have a significant impact on the study results. Three difficult issues related to detection limits were addressed; these were:

(1) Because the detection limits were close to potential regulatory limits, the choice of how to impute data for censored values (e.g., treating the censored values as zero, half the detection limit, equal to the detection limit, or as a statistically-imputed value) can affect whether the estimates of analyte concentration exceed potential regulatory limits.

(2) Censoring was particularly frequent with organic compounds. From a statistical perspective, a high proportion of censored data makes it difficult to reliably extrapolate below the limit of detection based on the small proportion of observed values.

(3) For many analytes of interest in this study, detection limits were determined by sample dilution and other procedural artifacts that were inherently different for each run and were determined individually as part of the analytical procedure. As a consequence, the range of detection limits often overlapped the range of detected values. This makes interpretation difficult because samples with higher detection limits have a greater latitude for containing undetected contaminants. These problems were most frequently encountered in sampling solids directly (both for inorganics and organics) and in measuring organic analytes in liquids.

To assess the effect of censored data on estimates of analyte concentrations, this study compared means in data where censored observations were treated as zero, as half the detection limit, and as equal to the detection limit. In general, the influence of censored data was modest when less than half the data were missing (e.g., estimates of the mean were generally less than 10 percent higher when censored values were treated as half the detection limit rather than zero). However, when more than half of the data were censored--as was frequently the case with organic analytes--the estimates of the mean could change substantially (e.g., 100 percent or more), depending on the method used to treat censored values.

This study explored two methods to statistically impute values for censored data, based on the distribution of observed data. The first method was termed the "linearized extrapolation method" and was similar to the "log-probability regression" method that was strongly recommended by Gilliom and Helsel [5] after thoroughly exploring several alternative techniques for handling censored water quality data. During preliminary analyses, the statistical distributions of the data on selected analytes were examined both by plotting various transformations of the data and by computing their skewness coefficients. These analyses demonstrated that, of the common distributions, most of the data sets were best fitted by the lognormal distribution. The detected values were assumed to be the upper end of the data set and the non-detected values the lower end of the data set. Using a computer program, the detected values were figuratively plotted on a logarithmic ordinate versus probability abscissa. Use of these scales linearized the lognormal data, and a straight line was fitted by "least squares" to the transformed detected values. This straight line was then extrapolated to allow a direct estimate of the logarithmic mean, standard deviation, and other summary parameters, as well as imputed values for the non-detected values. The values of the summary parameters and of the imputed values for the non-detects appeared to be reasonable representations in all cases of the (hypothetical) uncensored data sets with a uniform detection limit, including cases with greater than 50 percent censored values. On the other hand, where the detection limits varied for each data point in a data set--as they did for many of the organic chemicals--the results were more ambiguous.

Thus, the linearized extrapolation method was fairly straightforward when applied to inorganic chemicals, which generally have a detection limit that is either constant or has only two or three set values caused by different dilutions used during sample preparation for laboratory analysis. In contrast, the method worked poorly with some of the materials, particularly the organic analytes, where the range of detected and estimated non-detected values overlapped either partially or completely with the range of detection limit values. In this situation, a non-detect data point may result from an unusually high detection limit for the sample, masking a relatively high value for the sample. It could also result from a low value for the sample, but there is no way of distinguishing these two cases. That is, overlapping ranges for the detected values and the detection limits confound the estimation of values for the non-detects and makes the values difficult or impossible to estimate.

As an extension of the first method, this study also developed a set of statistical procedures to impute values for censored data in a weighted data set. This second method entailed fitting--and assessing the fit of--a lognormal distribution to the distribution of uncensored values above the detection limit. Based on the parameters defined by this best-fitting distribution, data were imputed by equally sprinkling values below the detection limit for censored observations along the cumulative density function defined by the lognormal parameters.

When different detection limits were encountered for different observations, this imputation procedure was repeated for each detection limit. This was done by first imputing values for the higher detection limit value (based on all uncensored observations above that level), and subsequently imputing values for censored data below the lower detection limits, using all uncensored observations above that level as a basis for imputation. Despite a number of advantages, two limitations of this second method of statistical imputation should be mentioned. A few censored samples had detection limits that were substantially higher than the observed values in the data set. The values of those data points could not be reliably estimated by this method. Hence, no effort was made to impute the value for a censored observation where the detection limit was higher than the mean of the observed values; in those cases, the censored observation was treated as missing data. A second limitation was that the statistical imputation procedures were not applied when there were too few uncensored values to ensure an adequate estimate of the lognormal parameters. As a result, the method was not applied to analytes where more than about half of the observations were censored. When there were sufficient observed data for this latter statistical imputation method to be used, the estimates of means were a little higher than estimates in which censored data were treated as one-half the detection limit.

Presentation of Results

The data from the EPA Field Sampling Project were reviewed as to sampling adequacy, data quality, and priorities for further study. These issues are discussed in detail for production and drilling sites. The issues are not discussed in detail for central pit and centralized treatment facilities, however, because the small number of such sites, and their non-random selection, did not permit detailed statistical analysis. Issues considered in the review of sampling adequacy included sampling precision and the adequacy of weights used to generate national estimates. Aspects of sampling precision considered were: (1) stratification and site allocation, (2) number of samples analyzed, and (3) variability of sample results.

A detailed assessment of the QA/QC aspects of the laboratory methods used was made by others. This study explored the statistical aspects related to censored data below the limit of detection. This study also checked for instances of inconsistencies and discrepancies in the study results as they relate to data quality.

Finally, this study attempted to provide a preliminary assessment of the current Field Sampling Project in terms of its implications for further study. For instance, this study identified analytes and areas of the country where further sampling might be warranted. It also suggested many analytes that may not need to be included in analyses of these additional samples.

Produced waters comprise most of the wastewaters from the exploration for, and production of, crude oil and natural gas. Recent surveys by the American Petroleum Institute [6] and EPA [2] estimated produced waters to be 98 percent and 83 percent, respectively, of the total. The difference can be attributed to API's method of estimation, which assumes a higher ratio of water-to-oil in Texas, Oklahoma, and Louisiana production sites. Conversely, EPA's method assumes substantially larger volumes of wastes in typical drilling pits, however, both estimates indicate the importance of production wastes.

National estimates based on the current EPA Field Sampling Project database of production sites are highly dependent on the values observed in three large production sites in the Texas/Oklahoma, Pacific Coast, and Gulf zones. This is because these regions were underrepresented in the survey, relative to their production. This study reviewed the weights (wastewater volume estimates as a proportion of the industry total for the whole country) that were developed by EPA for use with production sites and compared these with weights developed by API. The relative distribution of weights among zones was similar for both weighting methods. Moreover, mean estimates of analyte concentrations in production liquids were generally comparable whether EPA or API sampling weights were employed.

This study estimated the sampling precision provided by the current EPA Field Sampling Project. The confidence intervals around the estimated means were typically around $\pm$30 percent. However, sampling precision varied from analyte to analyte and, it should again be noted, the estimates are strongly influenced by the values from a small number of heavily weighted production sites.

Drilling wastewater data were also studied in some detail. The weights used by EPA were dependent on estimates of the size and distribution of different sized drilling pits and on the proportion of drilling wastes that were liquid. These estimates were based on a limited number of samples or on estimates obtained from state officials (which were difficult to verify). Data now available from an API survey [6] provide a larger database from which to develop sample weights. However, estimates of mean analyte concentrations using API rather than EPA weights were generally comparable.

The major limitation of the drilling wastes data is that sites from Texas/Oklahoma were seriously underrepresented, as only two drilling sites were randomly selected from the Texas/Oklahoma zone. Thus, the estimates of national means and percentiles are highly dependent on the values observed at those two sites. This degree of dependence on two heavily weighted drilling sites raises concerns about the stability of the national estimates regarding drilling wastes. The sampling precision associated with the current statistical protocol was estimated. The confidence intervals around the estimated mean concentrations were typically $\pm$30 percent for drilling liquids and $\pm$15 percent for drilling solids. However, the sampling precision varied considerably among analytes.

To establish priorities for further action or investigation, this study attempted to place into context the information on the wastes associated with petroleum exploration and production. This was done in three ways: First, the study summarized and compared mean and median analyte levels to water quality standards; second, the study described the proportion of wastes that exceeded water quality standards and various multiples thereof; and third, the study estimated the proportion of sites in which the concentrations of analytes exceeded water quality standards and various multiples thereof. Tables 2 through 5 list the latter two proportions for both production sites and drilling pit liquids, respectively, and for the 11 inorganic and 5 organic analytes of most concern. Drilling pit solids' TCLP leachates were generally of less concern and tables for these have been omitted. Note that EPA Water Quality Standards were used only as a risk-based datum for comparison and were not directly applicable to these production and drilling wastewaters.

TABLE 2. Percentage of Production Endpoint Liquids Exceeding Water Quality Standards

Analyte	No. Sam.	No. Det.	WQ Std. mg/l		1x			10x			100x		
					Est.	Low	High	Est.	Low	High	Est.	Low	High
Inorganics													
Barium	25	22	1.	a	50.5	33.1	67.8	15.8	7.3	29.0	2.2	0.7	5.8
Fluoride	22	22	4.	b	3.9	1.4	9.5	0.0	0.0	0.0	0.0	0.0	0.0
Chromium	25	6	0.05	a	20.0	8.0	40.0	4.0	0.0	12.0	0.0	0.0	0.0
Nickel	24	4	0.5	c	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cadmium	25	7	0.01	a	24.0	4.0	24.0	0.0	0.0	0.0	0.0	0.0	0.0
Lead	25	4	0.05	a	100.0	1.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0
Arsenic	25	9	0.05	a	70.0	52.0	88.0	0.0	0.0	0.8	0.0	0.0	0.4
Antimony	25	7	0.01	c	50.0	1.2	56.0	0.0	0.0	0.6	0.0	0.0	0.4
Boron	25	25	1.	d	99.2	97.6	99.8	41.9	25.7	59.7	0.2	0.1	0.8
Chloride	22	22	250.	b	99.9	99.6	100.0	81.7	67.5	91.2	9.1	3.7	18.7
Sodium	25	25	250.	e	76.1	60.2	87.7	39.7	23.9	57.5	10.9	4.7	21.8
Organics													
Toluene	22	17	10.	a	<0.1	0.0	0.1	0.0	0.0	*0.0	0.0	0.0	0.0
Benzene	22	17	0.005	a	99.9	99.9	99.9	96.5	91.1	98.8	34.2	19.1	52.2
2-Butanone	22	6	2.	c	9.1	0.0	18.2	0.0	0.0	*0.0	0.0	0.0	0.0
Phenol	22	11	1.	c	0.1	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Phenanthrene	22	5	0.002	f	100.0	100.0	100.0	9.1	0.0	22.7	0.0	0.0	9.1

Footnote Key

a. National Primary Drinking Water Regulation, 40 C.F.R. Part 141
b. National Secondary Drinking Water Regulation, 40 C.F.R Part 153
c. Based on an EPA reference dose for systemic toxicity
d. Based on a vegetation toxicity level, Sanks and Asano, p. 218 (1976) [7]
e. Assumes same criteria used in chloride
f. Based on an EPA, Characterization Assessment Division unverified reference dose
* Percentages >0.0 but <0.05

TABLE 3. Percentage of Production Sites with Production Endpoint Liquids Exceeding Water Quality Standard

Analyte	No. Sam.	No. Det.	WQ Std. mg/l		1x Est.	1x Low	1x High	10x Est.	10x Low	10x High	100x Est.	100x Low	100x High
Inorganics													
Barium	25	22	1.	a	27.5	8.0	47.1	3.4	0.0	11.3	2.9	0.0	10.3
Fluoride	22	22	4.	b	29.0	8.6	49.4	2.0	0.0	8.3	0.0	---	---
Chromium	25	6	0.05	a	21.7	3.6	39.8	0.0	---	---	0.0	---	---
Nickel	24	4	0.5	c	0.0	---	---	0.0	---	---	0.0	---	---
Cadmium	25	7	0.01	a	28.5	8.2	48.8	10.1	0.0	23.7	0.0	---	---
Lead	25	4	0.05	a	13.4	0.0	28.8	10.2	0.0	23.8	0.0	---	---
Arsenic	25	9	0.05	a	44.3	21.9	66.6	6.2	0.0	17.0	3.5	0.0	11.8
Antimony	25	7	0.01	c	0.5	0.0	3.8	0.0	---	---	0.0	---	---
Boron	25	25	1.	d	100.0	---	---	56.8	34.5	79.1	4.3	0.0	13.4
Chloride	22	22	250.	b	73.7	53.9	93.5	56.3	34.0	78.6	17.8	0.0	35.0
Sodium	25	25	250.	e	65.9	44.6	87.2	60.7	38.7	82.6	22.9	4.0	41.8
Organics													
Toluene	22	17	10.	a	0.0	---	---	0.0	---	---	0.0	---	---
Benzene	22	17	0.005	a	81.3	64.2	98.4	80.4	63.0	97.8	15.8	0.0	31.8
2-Butanone	22	6	2.	c	0.0	---	---	0.0	---	---	0.0	---	---
Phenol	22	11	1.	c	3.5	0.0	11.6	0.0	---	---	0.0	---	---
Phenanthrene	22	5	0.002	f	43.6	21.3	65.9	43.6	21.3	65.9	38.1	16.3	59.9

TABLE 4. Percentage of Drilling Pit Liquids Exceeding Water Quality Standards

Analyte	No. Sam.	No. Det.	WQ Std. mg/l		1x Est.	1x Low	1x High	10x Est.	10x Low	10x High	100x Est.	100x Low	100x High
Inorganics													
Barium	19	19	1.	a	54.3	35.7	72.0	6.3	2.3	14.7	0.1	<0.1	3.6
Fluoride	19	19	4.	b	11.3	4.6	23.1	<0.1	<0.1	0.1	0.0	0.0	0.0
Chromium	19	16	0.05	a	98.9	99.6	99.7	69.3	50.0	82.9	8.6	3.3	18.7
Nickel	19	17	0.5	c	50.0	31.7	68.3	0.6	0.1	2.2	<0.0	0.0	<0.1
Cadmium	19	14	0.01	a	99.7	98.9	99.9	52.3	33.8	70.3	0.3	<0.1	1.2
Lead	19	13	0.05	a	99.9	99.8	99.9	80.6	65.2	91.0	4.6	1.5	11.3
Arsenic	19	8	0.05	a	63.2	42.1	84.2	0.0	0.0	5.3	0.0	0.0	*0.0
Antimony	19	2	0.01	c	52.6	1.0	60.5	0.0	0.0	10.5	0.0	0.0	5.3
Boron	18	17	1.	d	90.3	79.0	96.3	3.0	0.9	8.1	<0.1	0.0	<0.1
Chloride	19	19	250.	b	86.4	73.4	94.2	52.5	34.0	70.5	16.6	7.4	31.0
Sodium	19	19	250.	e	90.5	79.8	96.3	50.7	32.3	68.9	10.1	4.0	21.1
Organics													
Toluene	18	7	10.	a	0.0	0.0	*0.0	0.0	0.0	*0.0	0.0	0.0	0.0
Benzene	18	2	0.005	a	80.6	69.4	91.6	27.8	16.7	38.8	0.0	0.0	*0.0
2-Butanone	18	6	2.	c	0.0	0.0	*0.0	0.0	0.0	*0.0	0.0	0.0	0.0
Phenol	17	3	1.	c	0.0	0.0	*0.0	0.0	0.0	*0.0	0.0	0.0	0.0
Phenanthrene	17	4	0.002	f	100.0	100.0	100.0	58.8	35.2	76.4	11.8	0.0	35.3

TABLE 5. Percentage of Drilling Sites with Drilling Pit Liquids Exceeding Water Quality Standards

Analyte	No. Sam.	No. Det.	WQ Std. mg/l		1x Est.	1x Low	1x High	10x Est.	10x Low	10x High	100x Est.	100x Low	100x High
Inorganics													
Barium	19	19	1.	a	53.6	30.6	76.6	4.5	0.0	14.1	4.5	0.0	14.1
Fluoride	19	19	4.	b	28.6	7.7	49.4	4.5	0.0	14.1	0.0	---	---
Chromium	19	16	0.05	a	77.9	58.8	97.1	57.9	35.1	80.7	27.0	6.5	47.5
Nickel	19	17	0.5	c	56.1	33.1	79.0	4.4	0.0	13.9	0.0	---	---
Cadmium	19	14	0.01	a	77.7	58.0	96.7	57.6	34.7	80.4	6.9	0.0	18.6
Lead	19	13	0.05	a	71.1	50.2	92.1	67.3	45.6	89.0	4.5	0.0	14.1
Arsenic	19	8	0.05	a	33.2	11.4	54.9	0.0	---	---	0.0	---	---
Antimony	19	2	0.01	c	5.3	0.0	15.6	0.0	---	---	0.0	---	---
Boron	18	17	1.	d	94.1	83.2	100.0	11.0	0.0	25.5	0.0	---	---
Chloride	19	19	250.	b	82.6	65.1	100.0	61.1	38.6	83.6	26.3	6.0	46.6
Sodium	19	19	250.	e	98.8	93.7	100.0	71.0	50.0	92.0	7.7	0.0	20.1
Organics													
Toluene	18	7	10.	a	0.0	---	---	0.0	---	---	0.0	---	---
Benzene	18	2	0.005	a	3.4	0.0	11.9	0.0	---	---	0.0	---	---
2-Butanone	18	6	2.	c	0.0	---	---	0.0	---	---	0.0	---	---
Phenol	17	3	1.	c	0.0	---	---	0.0	---	---	0.0	---	---
Phenanthrene	17	4	0.002	f	33.3	10.2	56.3	33.3	10.2	56.3	31.8	9.0	54.6

All of the production and drilling sites had at least one key analyte that exceeded water quality standards. For the production sites, the key analytes in greatest excess were benzene at 46 percent of the sites and phenanthrene at 41 percent. For the drilling pit liquids, the key analytes in greatest excess were either chloride or sodium in 67 percent of the sites and chromium at 23 percent; for drilling pit solids' TCLP leachates, the key analytes in greatest excess were sodium at 50 percent of the sites, lead at 35 percent, and cadmium at 11 percent. For many key analytes, substantial proportions of the sites exceeded 10 times the water quality standards and in some instances sites exceeded the standards by 1,000 times. Noteworthy in this regard are: for production sites, benzene, barium, chloride, sodium, and boron; for drilling pit liquids, phenanthrene, benzene, lead, chromium, cadmium, chloride, and sodium; and for drilling pit solids' TCLP leachates, lead.

Several limitations, however should be mentioned regarding these statistical analyses:

(1) The analyses are limited to national estimates. The samples within states and regions were too small to produce reliable sub-national estimates.

(2) The estimates are limited to: (a) production endpoint liquids; (b) drilling pit liquids; and (c) TCLP leachates from drilling pit solids. Again, the number of samples were too small to provide reliable estimates of analyte concentrations in drilling muds, tank bottoms, central pits, or centralized treatment facilities. Finally, drilling pit solids were excluded from these statistical analyses because analyte concentrations in solids (typically measured in mg/kg) are not directly comparable to water quality standards (typically measured in mg/l).

(3) A final issue concerns the appropriate water quality standards for comparison. In making comparisons in terms of human health effects, a primary drinking water standard or toxicity reference dose was selected. In the case of boron, chloride, and sodium, water quality standards were selected based on potential damage to vegetation. The boron limit is a toxicity-based value [8]; the chloride limit is based on salinity considerations [9] and is approximated by the secondary drinking water standards; and the sodium limit is equated with the chloride limit as a reasonable approximation.

A major issue concerns the effects of dilution as the effluent flows from the drilling pit or production endpoint into the receiving waters. Without detailed modeling of individual site characteristics, the effects of this dilution can not be estimated. Nevertheless, multiples--ranging from 10 to 1000--times the relevant water quality standard were used to demonstrate the potential effects of dilution. Because of space limitations, Tables 2 through 5 herein only show the 10 and 100 multiples of the standards.

Because the detection limits were very close to the relevant water quality standards for many of the analytes, estimates of the proportion of the wastewaters that exceed the water quality standards are heavily influenced by the method that is used to impute values for censored data. However, estimates of the proportion of wastewaters exceeding 10 and 100 times the water quality standard are much less affected by alternative methods of handling censored data; thus, much of the discussion focuses on these multiples.

Conclusions and Recommendations

There were six major conclusions reached in this statistical assessment:

(A) The EPA study is consistent with the similar API study;

(B) More sampling would be advisable to improve representativeness;

(C) The detection limit and censorship issues are manageable;

(D) A potential for serious environmental contamination is shown by the data;

(E) Many of the inorganic substances had waste liquid concentrations that exceeded drinking water standards. Of the set of substances selected for evaluation, there were more instances of inorganic compounds exceeding the standard than there were for organic compounds.

(F) Brines from the oil and gas extraction industry are potentially a major threat because of their potential capacity to damage vegetation.

Five major recommendations were made, three regarding additional sampling and two regarding the statistical analysis; these were, respectively:

(1) Any supplemental sampling should be conducted in the regions that are underrepresented in the earlier survey. Such sampling should be conducted until no single site accounts for more than 10 percent of all sample weights. This could be done by randomly sampling eight additional production sites (four in Texas/Oklahoma, two in the Plains region, and one in the West Coast region) and six additional drilling sites (five in Texas/Oklahoma and one in the Gulf region).

(2) In any further studies, replicate samples should be taken from production endpoints and from drilling pits. These would help to assess sample reliability. Increasing the number of samples might also increase the number of observations above the limits of detection and thereby improve the ability to statistically impute values for censored observations.

(3) To reduce the costs of additional sampling and laboratory analyses, a much shorter list of analytes/pollutants that one could realistically expect to find in wastewaters from the target industrial facilities should be used.

(4) Information from a recent survey by the American Petroleum Institute [6] that offers a larger database from which to develop zone weights should be used in statistical analysis of the wastewater data from this EPA Field Sampling Project.

(5) Statistical imputation techniques that use the information available from observed values to provide estimates for "censored" values should be utilized to substitute for values that are missing because they are below the limit of detection. Where there are too few observations above the detection limit to allow such statistical imputation, either of two approaches are suggested: (a) for estimating the proportion of wastewaters that exceed a particular contaminant concentration, non-parametric estimates--which do not require imputation--should be used; or (b) censored values should be treated as if they were one-half the detection limit (rather than zero).

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STATE OIL AND GAS AGENCY ENVIRONMENTAL REGULATORY PROGRAMS - HOW SUCCESSFUL CAN THEY BE?

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Introduction

State oil and gas regulatory agencies historically have dealt with non-environmental rulemaking. The traditional issues included allocation of production among competing interests and regulation of production rates to prevent unrestricted and wasteful withdrawal of the finite resource. Programs to restrict disposal of produced water came later after realization, especially in arid states, that uncontrolled dumping of large volumes of salt water posed serious threats to limited fresh water supplies.

In the late 1970's the Federal Safe Drinking Water Act set minimum national standards for state underground injection control (UIC) programs. With injection well permit review and approval, and enforcement of cementing and mechanical integrity testing programs, UIC became the first nationwide environmental program regulating disposal of oil and natural gas production wastes. Most states now have primary enforcement responsibility for oil and gas UIC programs and implementation is done through the state oil and gas agency.

State regulation of other methods of produced water disposal or of oil field sludges and solids varies among the states. Some states essentially have a single agency regulating waste disposal (e.g. Louisiana, New Mexico, Texas, West Virginia) while other states have split jurisdiction between onsite and offsite disposal (e.g. Kansas), while still others may have two or more agencies having regulatory jurisdiction over the same waste (e.g. California, Colorado, Wyoming). The placement of a particular state's regulatory program is likely due to a combination of events such as the existence of similar regulatory programs in state departments of health or environment, and the political climate and influence of the oil and gas industry at the time the environmental programs were initiated.

Now, as the states face additional federal regulatory requirements for oilfield waste disposal, it is important that a single state regulatory agency have jurisdiction over oilfield waste. Single agency jurisdiction for onsite and offsite waste disposal will allow the most efficient processing of industry permits and avoid dual jurisdiction and the conflicts that often arise among completing agencies.

However, to be effective and to demonstrate environmental commitment, an oil and gas agency administrating an environmental regulatory program should have, in addition to comprehensive regulatory authority, an adequate number of technical staff with a mix of environmental and industry expertise, and a management structure within the agency that will provide a focus for oil and gas environmental activities. These may include permitting, preparation of waste management procedures, contamination investigation, and coordination with other agencies, industry, environmental groups and the public.

This paper presents the case for administration of oilfield waste management and disposal programs by the state oil and gas agency while recognizing that in some states statutory and political constraints may not make such programs practicable.

Differing Program Jurisdictions

In 1988, there were 16 states listed by the Interstate Oil Compact Commission (IOCC) as being in the top ten for one or more of the following statistical categories: Oil production, gas production, producing oil wells, and producing gas wells (Table 1). The IOCC collected information for these and other states as part of their 1989 survey of waste management in oil and gas exploration and production operations. This paper utilizes that information and includes information on refineries and natural gas processing plants. Jurisdictional issues involving federally managed or Indian lands were not examined.

Elements of the IOCC waste survey included onsite and offsite regulation of landfarming, roadspreading, pits, surface water disposal, waste haulers, burial or landfilling, disposal wells and enhanced oil recovery injection wells. The states listed in Table 1 were contacted to obtain information on natural gas plants and refineries for this paper.

Examination of the IOCC waste survey results (Table 2) shows a wide variation among states in both the agencies regulating the wastes and the number of agencies within a state that have jurisdiction. For example, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas and West Virginia have most or all of their exploration and production waste program within the oil and gas agency. Alaska, California and Kentucky have all programs except the Class II injection program in state health, environment, or water agencies. For some disposal practices in these three states, two or even three non-oil and gas agencies are involved in state regulation. Additionally, local governmental bodies also may be involved.

The remainder of the states listed in Table 2 have split jurisdiction with the oil and gas agency usually regulating onsite disposal while other agencies regulate offsite hauling and disposal. Non-oil and gas agency regulation is most common for sludges and solids placed into waste pits; onsite and offsite disposal of produced water, especially by injection, is most commonly under the oil and gas agency.

For most states listed in Table 2, natural gas processing and oil refining are under state health and waste management agencies. The exceptions for natural gas processing are Louisiana, New Mexico, Texas and West Virginia. Oil and gas agency jurisdiction over refineries is even more limited. New Mexico has jurisdiction over non-hazardous wastes at refineries while in Louisiana, hazardous and non-hazardous wastes disposed of in injection wells are under the oil and gas agency while disposal of other hazardous or solid wastes is under the jurisdiction of the state environmental agency.

Organizational Structure

At least three key elements must be present for a state to have a basic environmental regulatory program. These are requirements for permitting, compliance evaluation and enforcement. However, to be comprehensive several additional program requirements are necessary. As identified by the IOCC in the June 1990 draft report of the Council on Regulatory Needs, these include contingency planning, financial assurance, waste tracking and hauler certification, data management, and public participation. The draft report discusses these requirements in some detail.

To most successfully implement a comprehensive oil and gas agency environmental regulatory program, an agency's organizational structure must be modified to provide an in-house group where environmental activities can be focused and which can complement the traditional petroleum engineering and geological services groups. The establishment of a designated environmental group with specific permitting and environmental response capabilities that reports directly to the agency supervisor demonstrates an agency's commitment to environmental issues.

As oil and gas waste issues and the regulations surrounding them become more complex, specialized expertise can be maintained only through a group of professionals permanently assigned to these tasks. With the possible exception of UIC permitting (which is not limited to waste disposal but includes injection for secondary and tertiary oil recovery), waste disposal activities should be separated from the traditional production permitting activities such as pooling, unitization, gas proration, correlative rights and resource conservation. Indeed, many traditional staffers may resent the addition of environmental considerations especially if their workload is increased and complicated by requirements not directly related to production. In this respect the critics of oil and gas agency environmental programs are correct: Some separation should be maintained between production activities and environmental regulatory activities within an agency. Therefore, the solution is a separate environmental group with responsibilities which include a statutory and regulatory responsibility to manage these wastes in a manner that protects public health and the environment.

The main benefits of an oil and gas agency environmental group are to provide a focus for agency environmental efforts including 1) waste disposal permitting (landfarming, pit disposal of water and solids, pond design engineering review), 2) permit review of gas processing and compression facilities, 3) review of oil and gas spill reports to evaluate fresh water pollution potential, 4) development of additional environmental rules and requirements in response to demonstrated need or to additional governmental mandates (e.g. Congress, EPA, State legislature), 5) to require, conduct, review and/or coordinate ground water or waste contamination investigations and remedial actions, and 6) acting as a liaison for the agency with other agencies, industry, environmental groups, and concerned citizens with respect to oil and gas related environmental problems. In New Mexico, all these functions are performed by the New Mexico Oil Conservation Division (NMOCD) Environmental Bureau with the liaison function between the agency and the public taking on an increasing importance.

A designated environmental group within the agency also provides increased environmental awareness by being able to advise other staff and industry operators on environmental aspects of existing or proposed rules. For example, New Mexico's Environmental Bureau provides written guidance documents for preparation of permits for commercial surface disposal facilities, clay or synthetic lined surface impoundments, natural gas processing plants, geothermal facilities and oil-field service companies. More recently, the bureau has been disseminating information to operators on the scope of the oil and gas exemption to the Subtitle C (Hazardous Waste) provisions of the Resource Conservation and Recovery Act (RCRA), and advising them of upcoming changes in the types and amounts of wastes managed under RCRA. Similar information is provided to other agency staff, and bureau personnel provide training and technical expertise to district field offices, especially in collection and preservation of water samples.

Technical Staffing Needs

Adequate technical expertise must be maintained both at the central office and district levels in order to properly evaluate permits and respond to reports of suspected or actual contamination. The number of experts necessary depends on the complexity of the program and types of facilities regulated. For example, NMOCD review of permits for underground injection, commercial surface disposal facilities, natural gas processing plants and refineries occurs in Santa Fe and

requires staff with both engineering (environmental and/or petroleum) and hydrogeological expertise.

For non-UIC permits, engineering aspects reviewed include process and wastewater streams, and treatment areas to identify likely areas for spills or equipment leaks (such as from valves or pump seals), demonstrate underground pressurized and gravity pipe integrity, and verify proper containment/storage of chemicals and drums. All solid and liquid process streams and wastestreams are included in the review as well as evaluation of engineering adequacy of any proposed waste pond liners or treatment systems (especially aeration systems for H_2S elimination).

A staff hydrogeologist will evaluate ground water contamination potential from any clay or unlined pits or surface impoundments receiving or proposed to receive non-hazardous liquid or solid wastes. In New Mexico, especially, fresh water supplies are scarce and in some areas non-existent. OCD-approved surface disposal into unlined facilities continues to be authorized in areas without fresh water, but hydrogeologists carefully evaluate each request. Requests for land treatment of wastes are reviewed for location suitability and application rates. At existing facilities, closure of unlined ponds is accompanied by review of past practices, and remedial action, if necessary, is initiated to remove floating product and dissolved hydrocarbons threatening adjacent fresh water supplies.

At the district office level, at least one staff person should be trained specifically in environmental matters including knowledge of compositional makeup of oil and gas wastes, current approved practices for disposal, local geologic and hydrologic conditions so that spills can be properly mitigated, and waste and water sampling methodology to provide proper response to complaints and potential ground water contamination. This environmental staff person would act as a direct liaison with central office staff reviewing environmental permits.

To attract and retain adequately educated and trained professional staff, salaries must be commensurate with similarly trained professionals. It is critical that this be accomplished. Government must not be the employer of last resort, taking only those who can't find jobs elsewhere. The area of oil and gas environmental regulation is becoming increasing complex. The survival of the oil and gas industry in the United States is dependent on rulemaking, implementation and enforcement that is scientifically sound, environmentally responsible and that is applied in a fair, even-handed manner. Payment of less than adequate salaries is unlikely to result in staff with adequate credentials to perform tasks (especially permitting) in an efficient and effective manner.

Building Citizen Confidence: Accountability and Public Interaction

The most difficult challenge facing a state oil and gas agency that administers an environmental regulatory program is to convince a skeptical public, including environmental groups and legislators, that a real commitment to environmental protection exists and the agency does not merely reflect industry desires.

The location of the oil and gas agency within state government framework can be important in this regard. While individual state government organization varies, many if not most states have a cabinet system in the executive branch similar to that of the federal government. In this system the responsibility for implementing laws rests in the office of the governor with clear lines of authority existing between that office and individual departments and lessor governmental divisions. Department heads and division directors are appointed and responsible to the governor for their actions. State executive departments such as health and environment, environmental quality, natural resources, energy and minerals, etc. are represented in the cabinet with this system.

The director of a state oil and gas agency located within a natural resources, or energy and minerals department, will be as equally responsible to the governor for administrating environmental laws pertaining to oil and gas waste as will the director of an environmental agency, and equally subject to ouster if his/her performance is not adequate. This government system, plus state statutory authority requiring the oil and agency to regulate waste disposal to protect public health and the environment, is the most effective means to assure accountability for administration of environmental regulations.

Similar lines of executive authority are present in states that have oil and gas commissions with the chairman and most members directly appointed and responsible to the governor. However, the system may be more tenuous if the oil and gas commission members are appointed to serve staggered terms and are required by law to be representative of one political interest or another.

State oil and gas agencies that are divisions of elected state corporation commissions or similar agencies are outside the control of the executive branch. The elected commissioners may or may not be interested in environmental issues, or they may be secondary to other regulatory concerns. In this instance clear legislative direction should be given to require that environmental protection be addressed in oil and gas waste disposal permits.

The past experience of an agency's environmental professional staff can assist in allaying public fear of industry control of an oil and gas agency program. Staff with previous experience in state environmental agencies complement other staff with industry experience by being able to communicate and work with their counterparts in the state's environmental agency. The cooperation and coordination between agencies becomes critical if some onsite and offsite oilfield waste management programs continue to remain in separate state government departments.

Oil and gas agency environmental staff must be able to work directly with both the public and with environmental groups. The form and extent of agency response to public concerns over oil and gas exploration and production, or to disposal of wastes will shape the public's view of the agency. Having technical staff with prior environmental agency experience can help in this regard. Involving the public by requiring public notice and considering public comment on proposed disposal facilities and other major permit actions may seen time consuming and counterproductive until the time and expense of lawsuits is considered.

Having staff trained to respond to public complaints will alleviate the image of an industry dominated agency. In New Mexico, money is budgeted for investigative water quality sampling, and OCD has cosponsored with the environmental agency free water testing in areas where large number of complaints of contamination have been reported. Near the Colorado border over 200 ground water samples have been tested since April, 1989, and discovery of significant natural gas contamination of domestic wells in one area has led to additional gas well completion requirements and to well workovers for many older gas wells. In this case having the ability to effectively respond to complaints and take action to begin remediation of the problem reduced public outcrys for a halt to drilling activity and for EPA and Congress to take action to require additional environmental studies and controls.

Although national and local environmental groups are considered nuisances or worse by many traditional oil and gas agencies (and even some state environmental agencies), it is crucial that agencies open a dialogue with these representatives. Irrespective of whether one agrees or disagrees with the level of activism, the political realities are that these groups are attaining greater political influence in state and local government affairs, especially in states that have diverse economies (i.e. California).

Those oil and gas agencies (and those producers) that believe environmental issues are only todays fad, or that superficial environmental rules will suffice will likely be rudely awakened since the solution generally sought in these cases is to enact strict inflexible statutory remedies and place the program in the state's environmental agency. In fact, the threat of the state environmental agency assuming jurisdiction or, worse yet (from their viewpoint), the federal government setting strict regulations, has been enough to cause many oil and gas agencies to rewrite rules, revise programs and focus on environmental issues.

The on-going debate on these matters will continue to direct attention on these issues for at least the next several years. State oil and gas agencies that already have successfully incorporated environmental programs into their traditional activities and remain responsive to public concerns will be required to make the least adjustments to future requirements.

Conclusions

To be successful with both the industry regulated and with the public, oil and gas agency environmental regulatory programs must be efficient and effective in permitting and in other duties (e.g. contamination investigation, information activities), and be responsive to public concerns about possible contamination and remedial action/cleanup of known problem sites. A combination of a central office environmental group and field office specialists provides the best method to accomplish this. The environmental group should include a mix of engineers and hydrogeologists, and salaries should be structured to hire and retain experienced staff. Field office staff should have knowledge of the types of wastes, local geology/hydrogeology, and waste and water sampling methods.

The more difficult challenge of convincing the public that the agency has a genuine concern about environmental matters can be attained by holding the agency accountable for its environmental program. This is accomplished through statutes and regulations that require waste disposal be conducted to protect human health and the environment, and through holding senior agency officials responsible for carrying out their duties. Additional confidence-building measures include having staff with previous experience in the state environmental agency, being responsive to citizen complaints and inquiries, issuing public notice and receiving public comment on major permit actions, and entering into a dialogue with state and local environmental representatives.

Those agencies with programs in place that follow the guidelines presented above are the least likely to suffer serious disruptions due to additional oil and gas environmental regulations, and will best serve the public and the industry they regulate.

Acknowledgement

I gratefully acknowledge the assistance of William R. Bryson, Intergovernmental Coordinator/Technical Director, Conservation Division, Kansas Corporation Commission who discussed at length with me some of the concepts I present in this paper.

Reference

Council on Regulatory Needs, Draft Report on Regulation of Exploration and Production Wastes, Interstate Oil Compact Commission, June, 1990.

Table 1: Top Ten State Production and Operating Statistics, 1988

	Oil Production		Producing Oil Wells		Gas Production		Producing Gas Wells	
1.	Texas	31.1%	Texas	191,424	Texas	35.8%	Texas	50,316
2.	Alaska	23.4	Oklahoma	73,846	Louisiana	26.3	Ohio	34,116
3.	Louisiana	13.4	California	47,852	Oklahoma	10.4	West Virginia	30,189
4.	California	11.7	Kansas	44,546	Wyoming	4.12	Pennsylvania	29,000
5.	Oklahoma	3.9	Ohio	29,625	New Mexico	4.06	Oklahoma	19,308
6.	Wyoming	3.5	Louisiana	27,433	Kansas	2.9	New Mexico	16,488
7.	New Mexico	2.2	Illinois	18,563	California	2.54	Louisiana	16,075
8.	Kansas	1.8	New Mexico	16,636	Colorado	2.53	Kansas	12,013
9.	North Dakota	1.4	West Virginia	15,865	Alaska	2.35	Kentucky	9,505
10.	Utah	1.0	Pennsylvania	13,255	Utah	1.44	Colorado	6,180

Source: Interstate Oil Compact Commission

TABLE 2. AGENCY JURISDICTION BY ACTIVITY AND FEDERAL STATUTE IMPLEMENTATION

ACTIVITY	ALASKA				CALIFORNIA				COLORADO			
	On-Site		Off-Site		On-Site		Off-Site		On-Site		Off-Site	
	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other
1. Landfarming		X(2)		X(2)		X(2)		X(2)	X		X	
2. Roadspreading		X		X		X(2)		X(3)		X		X
3. Pits	X	X(2)	X	X(2)		X(2)		X(2)	X		X	X
4. Surface Water Disposal		X		X		X(2)		X(2)		X		X
5. Wastehaulers	--	--		X	--	--		X	--	--		X
6. Burial or Landfill		X		X		X(2)		X(2)	X		X	X
7. Disposal Wells (Class II)	X		X		X		X		X		X	
8. Enhanced Oil Recovery Injection Wells	X		X		X		X		X		X	
9. Natural Gas Processing Plants	--	--		X	--	--		X(2)	--	--		X
10. Refining (Hazardous Wastes)	--	--		X	--	--		X(2)	--	--		X
11. Refining (Solid Wastes)	--	--		X	--	--		X(2)	--	--		X
Federal Statute Implementation												
1. Safe Drinking Water Act (UIC - Class II)	X		X		X		X		X		X	
2. Clean Water Act (NPDES)		X		X		X		X		X		X
3. RCRA - Subpart C (Hazardous)		X		X		X		X		X		X
4. RCRA - Subpart D (Non-hazardous)		X		X		X		X		X		X

Note: O&G = Oil and Gas. Numbers in parenthesis are number of non-oil & gas agencies having dual jurisdiction. Memorandums of agreement may be in effect to reduce overlapping responsibilities.

Sources: Interstate Oil Compact Commission, 1990; New Mexico Oil Conservation Division.

TABLE 2. AGENCY JURISDICTION BY ACTIVITY AND FEDERAL STATUTE IMPLEMENTATION

ACTIVITY	ILLINOIS				KANSAS				KENTUCKY			
	On-Site		Off-Site		On-Site		Off-Site		On-Site		Off-Site	
	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other
1. Landfarming	Prohibited		Prohibited		Prohibited		Prohibited			X		X
2. Roadspreading	Prohibited		Prohibited		X			X		X		X
3. Pits	X		X		X		Prohibited			X		X
4. Surface Water Disposal		X		X		X		X		X		X
5. Wastehaulers	--	--		X	--	--	X	X	--	--		X
6. Burial or Landfill		X		X	X			X		X		X
7. Disposal Wells (Class II)	X		X		X		X		EPA		EPA	
8. Enhanced Oil Recovery Injection Wells	X		X		X		X		EPA		EPA	
9. Natural Gas Processing Plants	--	--		X	--	--		X	--	--		X
10. Refining (Hazardous Wastes)	--	--		X	--	--		X	--	--		X
11. Refining (Solid Wastes)	--	--		X	--	--		X	--	--		X
Federal Statute Implementation												
1. Safe Drinking Water Act (UIC - Class II)	X		X		X		X		EPA		EPA	
2. Clean Water Act (NPDES)		X		X		X		X		X		X
3. RCRA - Subpart C (Hazardous)		X		X		X		X		X		X
4. RCRA - Subpart D (Non-hazardous)		X		X		X		X		X		X

Note: O&G = Oil and Gas. Numbers in parenthesis are number of non-oil & gas agencies having dual jurisdiction. Memorandums of agreement may be in effect to reduce overlapping responsibilities.

Sources: Interstate Oil Compact Commission, 1990; New Mexico Oil Conservation Division.

TABLE 2. AGENCY JURISDICTION BY ACTIVITY AND FEDERAL STATUTE IMPLEMENTATION

ACTIVITY	LOUISIANA				NEW MEXICO				NORTH DAKOTA			
	On-Site		Off-Site		On-Site		Off-Site		On-Site		Off-Site	
	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other
1. Landfarming	X		X		X		X		Prohibited		Prohibited	
2. Roadspreading	Prohibited		Prohibited		X		X		Prohibited		Prohibited	
3. Pits	X		X		X		X		X		X	
4. Surface Water Disposal		X		X	X	X	X	X	X		X	
5. Wastehaulers	--	--		X	--	--	X		--	--	X	
6. Burial or Landfill	X		X		X		X		X		Prohibited	
7. Disposal Wells (Class II)	X		X		X		X		X		X	
8. Enhanced Oil Recovery Injection Wells	X		X		X		X		X		X	
9. Natural Gas Processing Plants	--	--	X		--	--	X		--	--		X
10. Refining (Hazardous Wastes)	--	--	X	X	--	--		X	--	--		X
11. Refining (Solid Wastes)	--	--		X	--	--	X		--	--		X
Federal Statute Implementation												
1. Safe Drinking Water Act (UIC - Class II)	X		X		X		X		X		X	
2. Clean Water Act (NPDES)		X		X		X		X		X		X
3. RCRA - Subpart C (Hazardous)		X	X	X		X		X		X		X
4. RCRA - Subpart D (Non-hazardous)		X		X	X		X			X		X

Note: O&G = Oil and Gas. Numbers in parenthesis are number of non-oil & gas agencies having dual jurisdiction. Memorandums of agreement may be in effect to reduce overlapping responsibilities.

Sources: Interstate Oil Compact Commission, 1990; New Mexico Oil Conservation Division.

TABLE 2. AGENCY JURISDICTION BY ACTIVITY AND FEDERAL STATUTE IMPLEMENTATION

ACTIVITY	OHIO				OKLAHOMA				PENNSYLVANIA			
	On-Site		Off-Site		On-Site		Off-Site		On-Site		Off-Site	
	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other
1. Landforming	Not Authorized		Not Authorized		X		X		X		X	
2. Roadspreading	X		X		X		X		X		X	
3. Pits	X			X	X		X		X		X	
4. Surface Water Disposal	Not Authorized		Not Authorized		X		X		X		X	
5. Wastehaulers	--	--	X		--	--	X		--	--	X	
6. Burial or Landfill	X			X	X		X		X		X	
7. Disposal Wells (Class II)	X		X		X		X		EPA		EPA	
8. Enhanced Oil Recovery Injection Wells	X		X		X		X		EPA		EPA	
9. Natural Gas Processing Plants	--	--		X	--	--		X	--	--		X
10. Refining (Hazardous Wastes)	--	--		X	--	--		X	--	--		X
11. Refining (Solid Wastes)	--	--		X	--	--		X	--	--		X
Federal Statute Implementation												
1. Safe Drinking Water Act (UIC - Class II)	X		X		X		X		EPA		EPA	
2. Clean Water Act (NPDES)		X		X	X		X		X		X	
3. RCRA - Subpart C (Hazardous)		X		X		X		X		X	X	
4. RCRA - Subpart D (Non-hazardous)		X		X	X		X		X			X

Note: O&G = Oil and Gas. Numbers in parenthesis are number of non-oil & gas agencies having dual jurisdiction. Memorandums of agreement may be in effect to reduce overlapping responsibilities.

Sources: Interstate Oil Compact Commission, 1990; New Mexico Oil Conservation Division.

TABLE 2. AGENCY JURISDICTION BY ACTIVITY AND FEDERAL STATUTE IMPLEMENTATION

ACTIVITY	TEXAS				UTAH				WEST VIRGINIA			
	On-Site		Off-Site		On-Site		Off-Site		On-Site		Off-Site	
	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other	O&G Agency	Other
1. Landfarming	X		X		X	X	X	X	X		X	
2. Roadspreading	X		X		X	X	X	X	X		X	
3. Pits	X		X		X	X	X	X	X		X	
4. Surface Water Disposal	X		X		X	X	X	X	X		X	
5. Wastehaulers	--	--	X		--	--		X	--	--	X	
6. Burial or Landfill	X		X		X	X	X	X	X		X	
7. Disposal Wells (Class II)	X		X		X		X		X		X	
8. Enhanced Oil Recovery Injection Wells	X		X		X		X		X		X	
9. Natural Gas Processing Plants	--	--	X		--	--		X	--	--	X	
10. Refining (Hazardous Wastes)	--	--		X	--	--		X	--	--		X
11. Refining (Solid Wastes)	--	--		X	--	--		X	--	--		X
Federal Statute Implementation												
1. Safe Drinking Water Act (UIC - Class II)	X		X		X		X		X		X	
2. Clean Water Act (NPDES)	X		X			X		X		X		X
3. RCRA - Subpart C (Hazardous)		X		X		X		X		X		X
4. RCRA - Subpart D (Non-hazardous)	X		X			X		X	X		X	

Note: O&G = Oil and Gas. Numbers in parenthesis are number of non-oil & gas agencies having dual jurisdiction. Memorandums of agreement may be in effect to reduce overlapping responsibilities.

Sources: Interstate Oil Compact Commission, 1990; New Mexico Oil Conservation Division.

TABLE 2. AGENCY JURISDICTION BY ACTIVITY AND FEDERAL STATUTE IMPLEMENTATION

WYOMING

ACTIVITY	On-Site O&G Agency	On-Site Other	Off-Site O&G Agency	Off-Site Other
1. Landfarming		X		X
2. Roadspreading		X		X
3. Pits	X	X		X
4. Surface Water Disposal	X	X		X
5. Wastehaulers	--	--		X
6. Burial or Landfill	X	X		X
7. Disposal Wells (Class II)	X	X	X	X
8. Enhanced Oil Recovery Injection Wells	X		X	
9. Natural Gas Processing Plants	--	--		X
10. Refining (Hazardous Wastes)	--	--		X
11. Refining (Solid Wastes)	--	--		X
Federal Statute Implementation				
1. Safe Drinking Water Act (UIC - Class II)	X	X	X	X
2. Clean Water Act (NPDES)		X		X
3. RCRA - Subpart C (Hazardous)		X		X
4. RCRA - Subpart D (Non-hazardous)		X		X

Note: O&G = Oil and Gas. Numbers in parenthesis are number of non-oil & gas agencies having dual jurisdiction. Memorandums of agreement may be in effect to reduce overlapping responsibilities.

Sources: Interstate Oil Compact Commission. 1990; New Mexico Oil Conservation Division.

STATE REGULATORY PROGRAMS FOR DRILLING FLUIDS RESERVE PIT CLOSURE: AN OVERVIEW

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Abstract

In 1985 the Environmental Protection Agency began a study to evaluate drilling fluid waste disposal practices in the oil and gas industry. As a part of this study, a review of state agencies was conducted to determine the methods used and approved for disposal of drilling fluids and reserve pit contents. The data provided was in summary form and provided a good overview of the issue. In 1989 we developed a questionnaire sent to states in which the bulk of the drilling operations occur. The purpose of the questionnaire was to provide a more detailed review of disposal methods and to determine the major concerns of the state agencies about drilling fluid and reserve pit disposal practices. Questionnaires were also sent to federal agencies that control lands within various high oil producing states to determine their concerns. Drilling companies were also contacted about both their concerns and the current methods used for waste disposal. The data were evaluated in regards to disposal methods being tested by the drilling fluid service industry to determine if these methods were addressing the primary concerns about disposal practices.

Data showed that the methods of disposal of drilling wastes had not changed in the past few years for the majority of producing states. Some new regulations have been developed, but most new regulatory programs are under development and not yet promulgated. The driving forces changing disposal methods are future liability, landowner concerns and public awareness of the problem. It is hopeful that this review will provide a summary of disposal methods and associated problems, as well as an overview of the major concerns expressed by the various state and federal agencies, and the oil industry.

Introduction

In 1980, Congress amended the Resource Conservation and Recovery Act (RCRA) and temporarily exempted several types of solid wastes from regulation as hazardous wastes (1). Among the wastes exempted were wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy. Under RCRA, the Environmental Protection Agency (EPA) was to submit to Congress a report on these wastes by 1982. EPA did not meet that deadline, and the Alaska Center for the Environment sued. In December 1987, EPA submitted the final report to Congress (2). In this report EPA surveyed the various states for drilling activity, state regulatory programs, waste disposal programs and various problems associated with these activities. The final conclusions of the study recommended continued exemption under RCRA. Further studies on this subject are ongoing at this time.

Drilling fluid waste and disposal became a major topic of discussion in the oil and gas industry. Studies by various industry and state agencies are underway to determine the nature and extent of the problem. Methods of disposal and treatment of drilling wastes have been reviewed (3). Although a great many studies are being conducted, no summary of disposal methods and problems associated with them has been developed. This paper discusses such a survey. We attempt to summarize both state and industry involvement in disposal practices, problems found and future concerns.

Survey Report

The survey was sent to eleven states in which major drilling activity occurred (Table 1). State and federal agencies and industry in each state were contacted. The survey sheets sent to the various state and federal agencies asked six major questions (Table 2). Over 90% of the survey sheets sent out were completed. Industry was contacted through our area offices for responses to the same questions. Each area office was requested to survey their respective customers and supply information about disposal methods used and problems associated with their activities. All the offices surveyed responded to some degree. Produced water disposal was not an item discussed in the survey. However, most of the respondents included a discussion of the disposal of this waste stream.

Results of Survey

Most of the states contacted have regulations dealing with the holding and containment of drilling fluids and cuttings waste. Guidelines are general in nature for many of the states. Some have specific requirements which deal with the construction of the pit and containment of the waste. Alabama is considering having pit construction approved by engineers before use. Several states have strict regulations dealing with the disposal of waste with both a chemical and toxicity test required before disposal. Most states, however,

only require that the method of disposal prevent the contamination of surface or ground water sources. In some western states they also add protection of wildlife and livestock.

The major concern of all the states contacted was the integrity of the reserve pits, including construction and final closure. Other treatment concerns expressed were salinity (primarily high chloride) contamination, toxic additives or heavy metals, and hydrocarbon contamination. Regulations, however, in most states only superficially addressed these concerns. The exception to this rule is California which has both a chemical and a toxicity requirement. Louisiana requires a detailed chemical analysis which relates to the method used for disposal.

The report developed by EPA for the RCRA exemption discusses the various state regulations and summarizes various state activities. Thus, we will not repeat their report in this paper. For a thorough discussion of each state's regulations contact the state office.

Table 3 provides a summary of disposal methods used in the states surveyed. Percentages do not add up to 100% for each state. In many instances, more than one method of disposal is used for the same waste stream. The waste stream is frequently separated into liquid and solid portions for disposal. Rather than average the responses, percentages are given in ranges. Between 70-98% of the reserve pit contents were treated by dewatering the liquids and burial of the solids. Liquids were removed either by evaporation (the primary method in dry areas) or removal offsite and injection downhole. Flocculation of the solids from the liquids was also used in some areas. Liquids were treated in some areas and then discharged.

Landspreading of waste material is used in Louisiana and Oklahoma, and to a lesser extent in California and Texas. Landspreading of residue is used frequently in many of the states but was not clearly stated as such in the survey. Landfarming, either offsite or onsite, is used in Louisiana and Canada. Landfarming differs from landspreading in that the mixture is tilled more often, analysis of the waste is conducted to determine correct mixture ratios for treatment, and fertilizer is added to assist in degradation of the waste. Solidification is frequently used in Michigan and Oklahoma and to a lesser degree in California and Louisiana.

Treatment and discharge of the liquid phase is used in Louisiana and California and has limited use in other areas. Offsite disposal of waste is used in most states but at a low level (usually less than 10% of the time). Biodegradation is being tested in many areas but used commercially, to any extent, only in Louisiana. Injection of the drilling fluids and cuttings is being used in several areas. Either the liquid portion of the material is injected or both the cuttings and fluid are injected down the annulus. In California, mud and cuttings are used to pack off closed wells. Produced waters are usually removed and injected downhole.

In some western states produced waters are used for irrigation and, if possible, livestock. Oil muds are usually recycled and in some areas water-base muds are being recycled.

As noted in the survey, several methods are usually combined to dispose of drilling fluids and cuttings. Typically the liquids in the reserve pit are allowed to evaporate and the solids are buried onsite. If the area has a high rainfall, the liquids are hauled offsite and injected. In some instances flocculation chemicals are added to reduce the solids in the liquid phase before offsite disposal. In other instances the liquids are treated further and discharge while the solids may be solidified.

In some cases, the solids and some of the liquids are landspread and tilled into the surrounding lease area. Another typical method of disposal is injection of the waste down the annulus. In California, muds and cuttings are occasionally injected down a well that is being plugged and abandoned. Other systems are removed and recycled for further use in the same drilling area. Offsite disposal consists of landfills, landfarming, incineration, or treatment and disposal in commercial sites.

Summary of disposal technologies

Treatment offsite

Most offsite treatment systems process the mud and cuttings by solidification and burial. Some landfarm the material to degrade the organics and allow dilution to reduce the salt and metal loading. Some companies take all their mud and cuttings to incineration systems. The cost for this process is high; however, liability is reduced significantly and the site will never come back to haunt you. A few companies biodegrade the material before burial or landfarming while other companies recondition the mud offsite to be reused.

Treatment onsite

Offsite treatment is sometimes required by law. However, where possible operators prefer to treat the waste onsite to reduce costs. Treatment systems vary from simple discharge, dewater/backfill or injection operations to complex recycle operations. Treatment onsite, of mud and cuttings to reduce the size of the pit and recycle as much material as possible is appealing to operators for environmental and economic reasons. The following discussion details some of the methods discussed in the survey by industry, government, and oil field service companies.

Discharge

Before the 70's, many drilling operations would discharge the water portion of the drilling fluid after completion of the well into a local stream or river. This practice was particularly

prominent where rainfall reduced the chances of the liquid evaporating in a short period. Some states still allow the discharge of produced waters, if the water is of low enough salt content, to allow its use for livestock and irrigation. Some states still allow the discharge of treated reserve pit liquids if local water quality standards are met. Most states however have banned the discharge of drilling fluid liquids directly into streams or rivers. In Texas, Louisiana, and California a minor discharge permit must be obtained to allow discharges. In Louisiana, the discharge of produced waters is still allowed under certain conditions. Many western states still allow the discharge of produced waters with low chloride and hydrocarbon content for irrigation purposes.

Dewater/backfill

The oldest and most common method of closing a reserve pit is dewater/backfill. In the most simplistic scheme the water in the pit is evaporated and the solids are covered with the reserve pit wall and packed down. Excess water can be absorbed by adding straw or dirt to remove free liquids before the top soil is placed back on the pit. This is still the primary method of closure. Liability for these sites is under question. No extra attempts other than the clay and the drilling fluid, are made to stop leaching of free metals or hydrocarbons. Dewater/backfilling is cost effective. Reserve pits with low weight muds, no oil, and low heavy-metal content are dewatered/ backfilled with little or no impact to the environment. If the mud system uses bentonite, the sealing capacity of the clay material can reduce leaching from the site. Studies conducted on closed reserve pit sites, even on weighted muds systems, show little or no migration out of the pit (4).

Landspreading

Results of the survey indicated that in most states, low salt, non-oily muds are sprayed from the reserve pits out over the ground and allowed to soak into the soil. In many instances the farmers do not object to this treatment because they get added irrigation; and the low weight mud system can even help condition the soil. If the salt content, oil or heavy metal content is too high, this method of disposal may not be applicable. This method usually requires the farmer's written consent. The solids are normally tilled into the soil. In some areas the reserve pit is first treated by biodegradation to remove excess oil before a landspreading application.

In Louisiana, under 29B, strict regulations are now in place which control the landspreading of drilling fluids. Both onsite and offsite facilities have standards on heavy metals, salt content and oil content which must be met before a landspreading operation may begin.

Landspreading of the water and solids is cheap, requires little investment in equipment and, if properly conducted, can be very effective. The operator may have to hold on to the lease

for a longer period to allow the solids that will biodegrade to do so before returning the property to the landowner. If the solids contain excessive salt, oil or heavy metals the area may not be able to support plant growth and the area must be reconditioned. In the worst case, contaminants from the landspreading operation can leach into groundwater sources and possibly contaminate local drinking water supplies. In this event the cost of the drilling operation will go up significantly.

Annular injection

When a drilling operation is over and no commercial amount of oil or gas is found the operator can inject the used mud down the annulus for disposal. One concern noted in the survey, in using this method is that the casing protecting any ground water source can crack and expose the aquifer to the mud system. In some northern areas both the mud and cuttings are injected downhole. The cuttings are first ground into a fine powder for easy pumping, a zone is found that is fractured and the mud and cuttings are pumped into the zone for disposal. This is a relatively new method of disposal and the possible environmental implications are as yet unknown.

Another use of injection systems is for produced waters. In most states this is the primary, or only, method of disposal for produced waters. Injection systems are widely available and produced waters are routinely transported off site to these facilities. Most injection operations are regulated through the Underground Injection Control (UIC) program.

Solidification

In areas where dewatering the pit is not practical and hauling offsite for disposal is not viable the operator often turns to solidification. This process, first called thickening, necessitated the used of straw or dirt to stiffen the solids. Initially used to de-liquify the reserve pit, it became clear early on that this method also resulted in the reduction of heavy metals leaching from the pit. The operator has several choices for the reserve pit. He can dewater as much as possible and solidify the remaining amount or solidify the whole system. Solidification material can be cement agents, fly ash, kiln dust and/or portland cement. Several companies have developed polymers that can be used to solidify the reserve pit contents. The earliest solidification systems could not handle high oil content or high salt content. Several newer systems with mixtures of solidifying agents with polymers can handle much higher levels of these contaminants.

This method can be expensive depending on the agents used and the size of the pit. However, the advantages of being able to leave the material on site is appealing. The process used is simple but to fix the more complex mud systems the solidification process can become more difficult and more expensive. Oils and salt can still inhibit the mixture and allow leaching to occur at a greater rate than desired. The solidified material can have

higher than normal pH levels which can impact plant growth when left onsite. This method is used in California to develop a fixed granular pellet that is used as land cover in local landfills. The material has also been used for road beds and pot hole fill. In South America some companies are making bricks out of the material for foundation work.

Mobile Water Treatment - Flocculation

One of the methods of treatment of reserve pit waste is the use of polymer flocculation to dewater the pit contents. The method has been used in the past. Earlier pits were built to act as settling basins allowing the solids to fall out and the water to be recycled. As in water treatment systems, alum (aluminum sulfate) could be added to enhance the settling properties of the solids. Later, polymers were added to do this job. Now treatment systems are moved near the pit and recycle the solids through them. The polymer is added and the mixture is processed using centrifuge equipment. The mud systems need to be watched closely to prevent excess polymer from getting into the active mud system and flocculating the solids while drilling. This process of recycling for water is being used today in the Rockies, South East and North Central areas.

Another use of the flocculation process is to help in the dewater/backfill operation. In Michigan, high salt content mud systems are dewatered using polymer flocculation. Salt in the system will migrate to the water phase during this process thus reducing the salt content of the solids. This allows the operators to bury the solids on site while removing the high salt content water for disposal offsite.

Solids Control

One of the best methods to control and reduce the loss of mud and cuttings is through the use of good solids control equipment. These devices reduce the need for treatment of the solids and reduce the makeup mud needed to conduct the drilling operation. Solids control will be discussed again in the waste minimization section and under oil muds.

The cost of oil muds is high, thus good solids control equipment on oil mud systems is of great benefit. If properly used, the oil remaining on the cuttings can be reduced to less than 15%. Using this type of equipment in conjunction with a good landfarming program can be very effective in reducing the environmental impact.

Landfarming

Landfarming differs from landspreading in that the ratio of waste to soil is calculated and measured for maximum processing. The soil is usually conditioned and fertilized to enhance biodegradation of the organics. The soil/waste mixture is tilled more than once to increase oxygen uptake in the soil. Landfarming is used extensively in Canada and Louisiana. New

landfarm sites in Louisiana are not being developed and this method may see limited use in the future.

The landfarming of oil mud cuttings has been evaluated and tested in the U.S. since the 1950's. The concept is to allow natural bacteria in the soil to degrade the oil on the cuttings thus reducing any environmental impact. In Canada the primary method of disposal of oil based cuttings has been landfarming. Several concerns are the area of soil needed to dispose of the volume of cuttings and the level of oil on the cuttings. The type of oil, the internal phase, and any salt concentration. If the wrong ratios are used the reclamation of the soil to allow plant growth can take upwards of 3-4 years. This is a long time to hold onto a lease area.

Waste Minimization

Waste minimization is becoming a key phrase in EPA. The government is researching new and better ways to reduce waste production. Several waste minimization activities have been introduced by the oil field service companies. Products are developed that are less hazardous and more environmentally sensitive thus reducing the need for treatment or concern over disposal (5). Operators are using fewer products for the job, and maintaining the integrity of the remaining products to enhance their ability to return unused product to the supplier. According to the survey, the trend is to order only the amount of the product needed. This reduces oversupply at the rig site and the possible need to dispose of damaged product. Every attempt is made to use those materials at the rig site to reduce waste buildup. Solids control equipment is used to reduce the amount of waste going into the reserve pit. This reduces the size of the pit and thus the overall reclamation of the site when drilling is over. Operators are beginning to segregate the waste material during drilling by building reserve pits in segments. Each segment can carry a different type of mud system. By doing this the least toxic mud systems can be landfarmed on site at a low cost and the more toxic mud systems can be treated or removed offsite.

Oil fluids and cutting disposal

Only 10-15% of the muds used today are oil based. The possible problems of contamination due to improper disposal are greater when using oil muds. Several new technologies are being tested and researched on the disposal of oil based muds and cuttings.

Operators traditionally have used diesel based oil muds for onshore operations. The operator now has the ability to choose low toxicity oil based muds, e.g.mineral oil based, or synthetic hydrocarbons. Unique internal phases that are adapted to low salt or ion content that have less impact on plant growth are also being developed. These mud systems can play a major role in allowing landfarming or other treatment methods that otherwise would not be permitted.

Cuttings Washing

This method of cleaning oil-base cuttings prior to discharge is being used in the North Sea today. The method has several adaptations, including washing with diesel, solvent rinses, select washing, high power washing, etc. This method removes all but 10% of the oil on the cuttings. However, newer regulations reducing the oil loading on the cuttings to less than 10% are being proposed. Newer cuttings washing devices and mud systems are being developed to meet this requirement. This technology can also be applied to landbased operations where the reduction of oil on the cuttings may be helpful. One of the problems observed in the survey was what to do about the dirty wash water and how best to dispose of this waste.

Distillation

By using an electric or a gas fired furnace, drill cuttings can be heated to high temperatures thereby forcing the oil to vaporize. If the vapor is then placed into a condenser the oil is returned to a liquid state and reused in the active mud system. Water vapor can be condensed and sent offsite for disposal, or if properly treated discharged under a limited permit. Residual emulsion and oil mud additives can also be separated in some of the more advance units for possible reuse. The solids are discharged into a container for later disposal.

The process is "off-the-shelf" technology which has not been applied to the problem of drilling fluid treatment. The units, if not correctly built for drilling fluids, can be costly and have a low efficiency. High salt contents of the fluids can cause equipment corrosion, particularly at high temperatures. The high temperature and water/oil vapors are a fire hazard. Air emissions can be a problem and a permit for emissions may be required. If the temperatures are not controlled the oil can crack and the condensed material becomes useless as a mud re-additive. The solids which remain can be concentrated with heavy metals and may need further treatment to prevent environmental impact. The system, if used correctly, can reduce mud bills, recycle expensive oil and reduce the volume of waste generated. Several companies are now in the process of researching this technology and one company has developed a unit for use offshore.

Critical Fluids

Critical fluids technology is based on the same principle as the distillation unit. Instead of heat to strip the oil off the cuttings it uses a gas under pressure. The gas at elevated pressure becomes a liquid and washes the oil off the cuttings. Then, by releasing the pressure, the oil is separated and is recycled while the solvent becomes a gas and is recycled again. The process is expensive but eliminates the high temperatures and air emission problems.

Biodegradation

The biodegradation of oil and organics in a mud system has been going on for a long time. Landfarming and the fertilization and aeration of reserve pits are two forms of basic degradation processes. Recently because of the 29B regulations dealing with oil content, the use of in-situ biodegradation has increased. The latest technology is the development of a treatment system where the temperature, oxygen, oil, cuttings, bacteria and nutrient loads are all controlled. Under this process the oil content can be reduced very quickly to levels as low as 1%. The primary problem then is the removal of the dirty water and solids for disposal.

Bacteria may be inhibited in a high salt environment. Air emissions should not be a problem but under intense culture this may not be true. Under intensive culture a large volume of water may be required. Excess need for water may prohibit the use of this method in some areas. In some instances this method may result in changing the disposal problem from that of oil base cuttings to high volumes of dirty water disposal.

Incineration

Although this technology is very expensive, many operators are saying, "burn it." Future liability is reduced if the material is burned. The ash is usually solidified to prevent the leaching of any hazardous residue. In the long run this method may prove to be the least expensive. The cost of remediation of sites has increased dramatically over the past few years.

Summary

The traditional method of disposal of drilling fluids and cuttings is dewatering and burial. This was true when EPA conducted their study and is still true today, three years later. However, the increased attention to this problem has brought about a great deal of research and testing of newer methods of disposal and will eventually lead to more environmentally acceptable methods of disposal. Environmentally safer products are also being developed that will alleviate the disposal problem, both in water-base and oil-base mud systems.

One of the primary concerns noted in the survey is the construction and possible breakdown of the reserve pit during drilling operations. Survey responses indicate a high degree of concern over this issue and we foresee imminent regulatory changes in the next few years which will address this issue specifically.

An issue not addressed in this paper but noted during the survey is the increased awareness and response to drilling operations by landowners and the public. Except for Louisiana,

new laws and regulations were not the major or even minor driving force in change. Changes were occurring because landowners were becoming more aware of disposal practices and requiring operators to adjust their methods to meet future land use requirements. Both industry and government noted the need to address this issue in a realistic manner that both protects the environment while limiting the cost on drilling operations.

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TABLE 1: STATES SURVEYED

Alabama
Alaska
California
Colorado
Kansas
Louisiana
Michigan
New Mexico
North Dakota
Oklahoma
Texas
Wyoming

TABLE 2: SURVEY QUESTIONNAIRE

1. Briefly discuss your state/federal restrictions dealing with reserve pits, drilling fluids and cuttings disposal.

2. What are the major concerns in your state dealing with the disposal of drilling fluids and cuttings and reserve pits closure?

3. May we have a copy of your regulations dealing with disposal operations?

4. What methods of disposal are practiced in your state?

5. Please describe the major problems you have noted with disposal practices in your state.

6. Does your state plan in the near future to change disposal regulation in any way? If so, please described the changes proposed.

TABLE 3. DISPOSAL METHODS USED IN VARIOUS STATES BY PERCENT

METHOD	AL	AK	CA	CO	LA	MI	NM	ND	OK	TX	WY
Dewatering/ backfill	95	80-95	24	98	10	50-90	98	92	60-85	85	70-95
Landspreading	1-10		5-10		10		1		<40	2	
Landfarming	1				40					1	<1
Solidification		1	5-10		10	25-90		2	< 25	1	2-5
Discharge of Liquid		1	18		20-50				<1		5-10
Flocculation			20-30		10	1				1	5
Offsite Disposal	3-10	1-5	10-20	1		10	1	4	5-10	10	15
Biodegradation					5						
Injection	95	10 (mud) 95 (liq)	56	1	50	90-100 (liq)		1	1-5 mud 80-100 liq		15
Recycle		1-5	5-10		5			1	10	10	<1
Other		1-10	40					1			<1

THE STATES' REGULATION OF EXPLORATION AND PRODUCTION WASTES

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Director of Production Services
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The Interstate Oil Compact Commission has established a Council on Regulatory Needs to review the states regulation of exploration and production (E&P) waste. As guardians of the resource and obligated to oversee its proper development and production in an environmentally sound manner, the producing states are committed to the success of the Council's investigation of E&P waste management practices and regulations.

The Interstate Oil Compact Commission (IOCC) is the organization of oil and gas producing states dedicated to resource conservation, authorized by Art. 1, Sec. 10 of the United States Constitution and ratified by Act of Congress. The IOCC represents 35 states, 29 member and 6 associates, working together in a program of waste prevention (fig. 1). Individual state legislatures have voted to become an IOCC member which gives the Governor a vote on the Commission. The Governor may appoint an official representative to the Commission to exercise that state's vote in the Governor's absence.

The IOCC derives the bulk of its funds from the states; it does not receive any funds from petroleum industry. Each member state contributes to the support of the Commission. The IOCC further is engaged in various specific projects in cooperation with state and federal agencies such as the U.S. Environmental Protection Agency and the U.S. Department of Energy. It accepts funds from the federal government in support of this work. It also receives miscellaneous funds from seminars, professional meetings, and publication of books.

The IOCC has been assisting states in developing their oil and gas regulatory programs since 1935. More than 99 percent of the oil and gas produced in the United States is produced within the borders of and is regulated by member states of the IOCC.

In January, 1989, the IOCC formed the Council on Regulatory Needs to assist the EPA in determining where the states' regulation and enforcement of existing programs could be improved. The Council is comprised of 12 state regulatory agency members. The Council is supported in its efforts by a nine member advisory committee; of whom three represent state regulatory agencies, three represent industry, and three represent public-interest/environmental groups. The Council is assisted by five representatives of EPA, two from the U.S. Department of Energy, and two from industry, who act as official observers. Governors George Sinner of North Dakota and Garrey Carruthers of New Mexico are co-chairs of the Council (fig. 2).

An organizational meeting of the Council was held in February, 1989 in Denver, Colorado. At that meeting, a committee structure was formed with the Technical Committee consisting of three subcommittees; Pits, Land, and Commercial, and the Administrative Committee consisting of four subcommittees; Personnel and Resources, Organization and Coordination, Statutory Authority, and State and Federal Relations. At the Council meeting in June, 1989, in Reno, Nevada, the Technical Subcommittees submitted initial criteria for discussion by the full Council. The Administrative Subcommittees presented their first draft reports to the Council at its meeting in Tulsa, Oklahoma in December 1989.

In early 1990, the separate committee reports were revised and combined into a single document. This document was presented as a draft final report at the June, 1990 IOCC meeting in Bismarck, North Dakota. From June, 1990 until August, 1990, final changes were made to the document so that the council could present its final report at the December, 1990 IOCC meeting in Phoenix, Arizona.

The purpose of the Council is to recommend effective regulations, guidelines, and/or standards for state-level management of oil and gas production wastes. EPA has concurred in this purpose, stating that " . . . IOCC is leading an effort . . . that will use . . . information gathered by EPA to develop IOCC guidelines for state oil and gas waste management regulations" (Lowrance 1989). The technical and administrative criteria proffered by the Council on Regulatory Needs will be published and disseminated to the states as examples of the range of "elements" necessary for effective state regulatory programs for E&P wastes. The criteria by themselves are not intended to form the sole basis of any future federal statutory or regulatory authorities that may be sought by EPA for oil and gas production wastes.

The Council's criteria address waste management practices that are unique to E&P operations and wastes that were determined by EPA to be exempt from the hazardous waste management requirements of Subtitle C of RCRA. These narrowly defined wastes include drilling muds and cuttings, produced water and associated waste. Wastes that are uniformly regulated by RCRA hazardous waste management requirements as well as general industrial wastes such as solvents, off-specification chemicals, commercial products, household wastes and office refuse are not addressed by these criteria.

These criteria do not address disposal of produced water by injection or surface discharge -- waste management practices that are regulated by EPA or by the states under authority of the federal Safe Drinking Water Act and federal Clean Water Act.

An effective program for the regulation of E&P wastes should include, at a minimum: statutory authority which adequately details the powers and duties of the regulatory body; statutory authority to promulgate appropriate rules and regulations; statutes and implementing regulations which adequately define necessary terms of art; provisions to adequately fund and staff the program; mechanisms for coordination among the public, government agencies and regulated industry; and technical criteria for E&P waste management practices.

An effective state program should contain a clear statement of the program's goals and objectives. Such goals should include, at a minimum, protecting human health and the environment from the mismanagement of E&P wastes while maintaining an economically viable oil and gas industry and encouraging waste minimization as a means of achieving such a goal.

These criteria are intended to provide guidance to the states in the formulation, development and evaluation of oil and gas environmental regulatory programs. Fundamental differences exist from state to state, and within regions within a state, in terms of climate, hydrology, geology, economics and methods of operation which may impact on the manner in which oil and gas exploration, development and production is performed. State oil and gas programs can, and should, vary from state to state and within portions of a state.

The process by which these criteria are incorporated into state programs is a function of and within the discretion of the responsible state agency. It is recognized that state programs must vary in order to accommodate differences in climate, hydrology, geology, economics, and methods of operation or to accommodate individual differences in state administrative procedures or law. Furthermore, in some instances, in order to accommodate regional, areal, or individual differences within a state, it is appropriate for site-specific waivers or variances to be allowed for good cause shown.

Basic Administrative program requirements for E&P waste should, at a minimum, include provisions for permitting, compliance evaluation and enforcement. The report further explains that:

"A state must have a regulatory mechanism to assure that wastes generated during oil and gas exploration and production operations are managed in an environmentally responsible manner. A program to achieve that objective may rely on one or more mechanisms, including issuance of individual permits, issuance of permits by rule, establishment of regulatory requirements by rule, issuance of general permits, registration of facilities, and/or notification of certain activities undertaken pursuant to general regulations. The regulating state agencies should have authority to refuse to issue or reissue permits or authorizations if the applicant has outstanding, finally determined violations or unpaid penalties, or if a history of past violations demonstrates the applicant's unwillingness or inability to comply with permit requirements. Individual permits for specific facilities or operations should be issued for fixed terms. In the case of commercial or centralized facilities, permits generally should be reviewed, and revised if necessary, no less frequently than every five years. Where similar requirements are mandated by two or more regulatory programs being administered by the same state agency, those requirements should be combined, in a common permit or otherwise, to assure that the regulatory process is made as efficient as practicable."

State programs generally should contain the following compliance evaluation capabilities:

Procedures for the receipt, evaluation, retention, and investigation for possible enforcement action of all notices and reports required of permittees and other regulated persons. Investigation for possible enforcement action should include determination of failure to submit these notices and reports.

Inspection and surveillance procedures that are independent of information supplied by regulated persons to determine compliance with program requirements, including: the capability to make comprehensive surveys of facilities and activities subject to regulation in order to identify a failure to comply with program requirements by responsible parties; the capability to conduct periodic inspections of regulated facilities and activities at a frequency that is commensurate with the risk to the environment that is presented by each facility or activity; and the authority to investigate information obtained regarding violations of applicable program and permit requirements.

Procedures to receive and assure proper consideration of information submitted by the public about alleged violations and for encouraging the public to report perceived violations. Such procedures should not only involve communications with the public to apprise it of the process to be followed in filing reports or complaints, but also how the state agency will assure an appropriate and timely response.

Authority to enter any regulated site or premises in which records relevant to program operation are kept in order to copy records, inspect, monitor or otherwise investigate compliance with permit conditions and other program requirements.

Investigatory procedures that will produce an appropriate paper trail in support of evidence admissible in an enforcement proceeding.

An effective state program should provide that a state permit does not relieve the operator of the obligation to comply with federal, local or other state permits or regulatory requirements.

With respect to violations of the state program, the Council believes that the state agency should have the authority to take some or all of the following enforcement action: issue a notice of violation with a compliance schedule; restrain immediately and effectively any person by order or by suit in state court from engaging in any impending or continuing unauthorized activity which is causing or may cause damage to public health or the environment; establish the identity of emergency conditions which pose

an imminent and substantial human health or environmental hazard that would warrant entry and immediate corrective action by the state agency after reasonable efforts to notify the operator have failed; sue or cause suit to be brought in courts of competent jurisdiction to enjoin any impending or continuing violation of any program requirement, including any permit condition, without the necessity of a prior revocation of the permit; require by administrative order or suit in state court, that appropriate action be undertaken to correct any harm to public health and the environment that may have resulted from a violation of any program requirement, including but not limited to establishment of compliance schedules; revoke or suspend any permit upon a determination by the state agency that the permittee has violated the terms and conditions of the permit, failed to pay an assessed penalty, or used false or misleading information or fraud to obtain the permit; or assess administrative penalties or seek in court civil penalties or criminal sanctions, including fines and/or imprisonment.

In some states, enforcement remedies include authorities to cause cessation of production or transportation of product, seizure of illegal product, and bond forfeiture.

Additional Administrative program requirements of an effective state program would include: contingency planning; waste hauler certification; waste tracking; location of closed disposal sites; data management; sufficient numbers of properly trained personnel; legal support; technical and administrative support; properly trained field inspectors; adequate funding; formal agreements between state agencies with E&P waste management responsibilities; and maintain coordination between state and federal agencies involved.

The Council has recommended that the following technical criteria be a part of an effective state program.

- Facilities and sites used for the storage or disposal of wastes derived from the exploration and production of oil and natural gas should be operated and managed at all times to prevent contamination of water, soil and air, protect public health, safety and the environment, and prevent property damage.

- Facilities and sites operated for the storage or disposal of E&P wastes should not receive, collect, store or dispose of any wastes that are listed or defined as hazardous wastes and regulated under Subtitle C of RCRA, except in accordance with state and federal hazardous waste laws and regulations.

- Technical criteria for siting, construction and operation of E&P waste disposal facilities should be flexible enough to address site-specific or regional conditions, based on findings by the regulatory agency.

- Disposal of untreated produced water, drilling muds, drilling fluids, and tank bottoms in municipal solid waste landfills should be prohibited. Low volume E&P wastes, such as oily rags and drained filters, and any other E&P wastes that are similar in composition to routine municipal solid waste streams may be disposed of in municipal solid waste landfills.

- As in any aspect of waste management, there are some general, sound practices that should be employed. These practices, which include waste minimization, not only serve to protect human health and the environment, but also tend to protect waste generators from long-term liabilities associated with waste disposal. As a rule-of-thumb, the choice of a waste management option should be based upon the following hierarchy of preference:

  Source Reduction -- reduce the quantity and/or toxicity of waste generated;

Recycling -- reuse or reclaim as much of the waste generated as possible, and whenever possible, hydrocarbons should be combined with crude oil, condensate or natural gas liquids;

Treatment -- employ techniques to reduce the volume or the relative toxicity of waste that has been unavoidably generated;

Proper Disposal -- dispose of remaining wastes in ways that minimize adverse impacts to the environment and that protect human health.

- Nothing in these criteria mandates onsite testing for every hazardous constituent that may be present in E&P wastes. Rather, these criteria call for appropriate onsite testing of E&P wastes prior to disposal for such characteristics as organic content, pH, salinity, hydrogen sulfide content, and ignitability--the chemical characteristics that are thought to be the primary constituents of concern in E&P wastes. The Council recognizes, however, that waste management practices and regulatory requirements, would be improved by obtaining a more complete knowledge through testing and analysis of the range of hazardous and toxic constituents in E&P wastes.

The states are encouraged to establish and implement specific performance standards and design specifications based on site-specific or regional differences in geology, hydrology, climate and waste characteristics.

The Council has made specific recommendations on reserve, production and special purpose pits regarding permitting, siting, construction, operation, and closure. The Council's recommendation identifies those items it feels each state should consider necessary for the states to properly regulate pits.

Those elements necessary for an effective state program to regulate, landspreading, burial and landfilling, roadspreading, and commercial and centralized facilities are also included in the Council's report. Each of these practices have been examined and specific technical, siting, construction, operating, and closure requirements have been recommended.

The Council also recommended five items to consider for future work:

- The Council encourages industry and individual states to increase their efforts to characterize chemical constituents of exploration and production wastes.

- The Council encourages research by industry, the federal government, state-affiliated academic institutions, and public-interest groups into effective ways of minimizing and reusing wastes generated in the nation's oil and gas fields.

- The Council recognizes that contamination problems exist from the use of past management practices and from violation of regulations and laws. As such, it recommends that IOCC, EPA and the states work together to evaluate and recommend remediation approaches.

- The Council recommends that IOCC review and act upon EPA's recommendations that may result from the agency's mid-course review of state UIC programs. IOCC should incorporate in these technical criteria any changes that may be needed to address problems or improvements in state-administered UIC programs.

- The Council encourages the state and federal governments to examine the benefits and economic and energy impacts of changes in E&P waste managements requirements.

Finally, the Council issued the following implementation strategy:

This report represents IOCC's initial effort to help the states and EPA improve E&P waste management programs. This report:

- Demonstrates the commitment of the governors of oil and gas producing states, EPA, state agencies, environmental groups and industry to work together for environmental change and improvements;

- Serves as a model for future efforts and substantiates IOCC's position as an appropriate forum to develop comprehensive approaches to multifaceted and complex oil and gas related environmental issues; and

- Establishes a baseline of performance that can be used for both the administrative and technical aspects of E&P waste management. This baseline is useful to federal and state regulators, legislators, and oil and gas operators.

To achieve successful implementation, the Council recommends the following strategy:

- Secure grants to provide adequate funding for implementation of follow-up recommendations and continued active participation of all affected parties.

- Communicate the criteria of this report to EPA, state agencies, operators, and other interested parties through direct contact, at E&P waste management conferences and symposia, in a series of one-day workshops hosted by state agencies and involving regional EPA offices, state and tribal agencies, oil and gas operators, trade associations, environmental groups, and through other mechanisms as may be appropriate.

- Continue to build consensus and improve this document. To this end, IOCC plans to widely circulate it to federal agencies (EPA, DOE, DOI), state oil and gas agencies, state environmental agencies, and national and regional trade associations, seeking endorsement as qualified endorsement. The Council further recommends updating this document every two years.

- Use this document as a basis for conducting IOCC coordinated peer reviews of state E&P waste management programs and as a basis for peer review of federal agency programs. Teams of senior regulatory personnel should visit agencies and review programs using this document as a baseline of performance and for making recommendations for improvement.

- Use IOCC as a clearinghouse for changes and revisions to state and federal regulatory and legislative programs.

- Pursue improvements in data management, waste characterization, and other areas.

The IOCC has just begun work with the EPA on a state review program, a training program, and a data base management program.

In conclusion, the Governors and Official Representatives of the IOCC are committed to environmentally sound practices regarding E&P wastes and continue to support the Council on Regulatory Needs as a unique forum where interested parties can work together for improvement in environmental regulation.

Membership of the IOCC

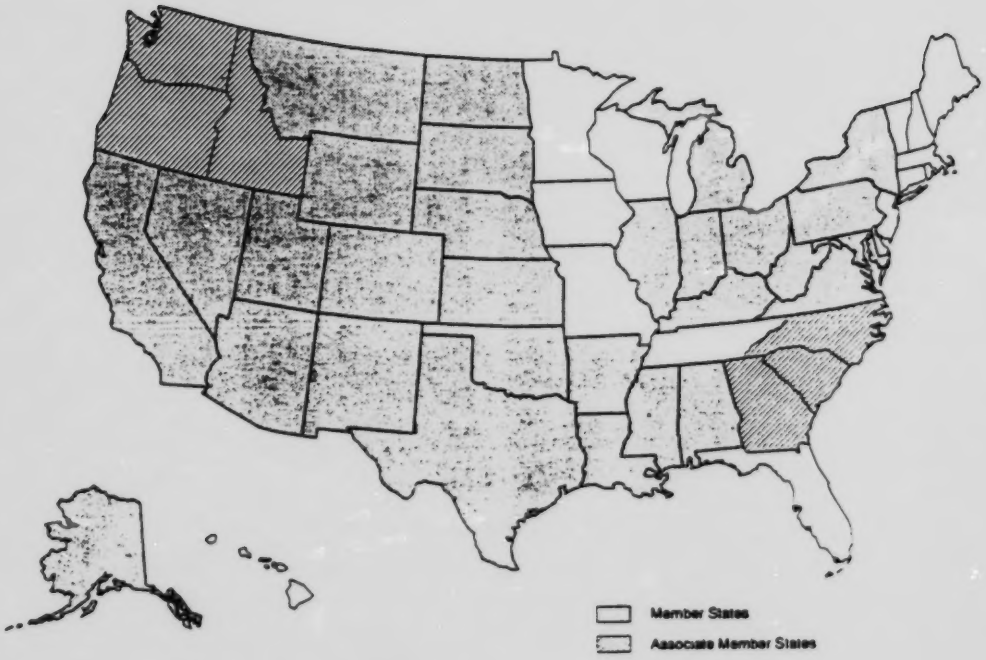

Fig. 1

IOCC COUNCIL ON REGULATORY NEEDS

Council Members

Member	Subcommittee	Affiliation
Donald B. Basko	Pits	Wyoming Oil & Gas Conservation Commission
J. Patrick Batchelor	Administrative Committee Chairman	Louisiana Dept. of Natural Resources
William R. Bryson	Technical Committee Chairman	Kansas Corporation Commission
Tom Edmondson	Land	Illinois EPA
James E. Erb	Organization and Coordination	Pennsylvania Dept. of Environmental Resources
J. Edward Hamrick	Pits	West Virginia Dept. of Natural Resources
Mike Bates	Land	Arkansas Pollution Control and Ecology
Jack Badgett	Commercial	Oklahoma Industrial Waste Division
Jeff Mach	Pits	Alaska Dept. of Environmental Conservation
M.G. (Marty) Mefferd	State and Federal Relations	California Dept. of Conservation
Jerry W. Mullican	Organization and Coordination	Texas Railroad Commission

Advisory Panel

Patti Saunders	Land	Alaska Center for the Environment
Randolph C. Bruton	Statutory Authorities	TIPRO
James W. Collins	Commercial	American Petroleum Institute
Charles D. Davidson	Personnel and Resources	Oklahoma Corporation Commission
David M. Flannery	Statutory Authorities	Appalachian Producers
Philip M. Hocker	Statutory Authorities	Mineral Policy Center
Terri Lorenzon	Organization and Coordination	Wyoming Environmental Quality Control
Michel J. Paque	State and Federal Relations	UIPC
Chris Shuey	Commercial	Southwest Research and Information Center
William R. Smith	Pits	Colorado Oil & Gas Conservation Commission

Observers

Bill Hochheiser	Pits	Department of Energy
Nancy Johnson	State and Federal Relations	Department of Energy
Harold W. Yates	Land	American Petroleum Institute
Joel H. Robins	Pits	American Petroleum Institute
Charles W. Perry	Commercial	Environmental Protection Agency
Dave Bussard		Environmental Protection Agency
Mike Fitzpatrick		Environmental Protection Agency
Bob Tonetti		Environmental Protection Agency
Melissa Ward		Environmental Protection Agency

Editing Committee Members

J. Patrick Batchelor, William R. Bryson, Tom Edmondson, James E. Erb, David M. Flannery, Philip M. Hocker, Terri Lorenzon, Chris Shuey, Bill Hochheiser, Nancy Johnson, Harold W. Yates

Fig. 2

A STUDY OF THE LEACHATE CHARACTERISTICS OF SALT CONTAMINATED DRILLING WASTES TREATED WITH A CHEMICAL FIXATION/SOLIDIFICATION PROCESS

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G. Johnson, PhD., Oklahoma State University

Introduction

Geologic evaporite and salt deposits are often encountered during oil and gas drilling operations. Because of the deleterious effect of salt to the surface biological environment (e.g. soil and vegetation) the disposal of salt is closely regulated by state and federal agencies and must be carefully undertaken.

Generally, salt contaminated drilling wastes are typically either injected into an approved disposal well; disposed of offsite in commercial surface impoundment facilities; contained and eventually (by evaporation or CFS treatment) buried in onsite noncommercial reserve pits or drilling sumps; or spread in calculated amounts over the land, as in soil farming.

The burial of salt contaminated drilling wastes is a common practice and one of the most cost effective methods for disposing of these type wastes. However, concerns have been raised in recent years related to this method of disposal by environmental groups, as well as soil conservation and water quality control agencies.

Of particular concern is the effect these salt contaminated pit wastes have upon soil productivity (in the near proximity to the pit burial site) as well as the potential for migration of the salt out of the buried mass and into nearby ground water sources (aquifers).

While it is generally accepted that salt contaminated wastes which are covered with an insufficient layer of top soil or overburden material will inhibit or, in some cases, totally prevent root development and plant growth, the potential pollution of adjacent freshwater shallow aquifers is a complicated issue and the subject of continuing debate.

The oil and gas industry must be committed to the care and safekeeping of our environment and work toward the development of technologies and methods aimed at minimizing, recycling, and disposing of wastes generated in the process of exploring and developing our nations energy resources.

In keeping with that commitment, Mobil began, in the early 1980's, to examine new and better methods for disposing of drilling wastes at the site upon which those wastes were generated as opposed to hauling the same wastes offsite to commercial disposal facilities.

A technology which lends itself to this onsite disposal practice is a process commonly known as "Chemical Fixation and Solidification", (CFS).

While this technology has been in commercial existance for more than twenty years, only in the last ten years has it attracted the attention of environmental scientists and engineers, regulatory officials, and waste generators.

The CFS process involves the adding and mixing of a chemical agent(s) to the waste material for the purpose of fixating, stablizing, and solidifying the waste material. These terms are used interchangably by the industry to describe the treatment of semi-solid wastes to form a "quasi monolithic" solid -relatively impermeable to percolating surface water.

While the solidified waste does not result in a mass with the characteristics of concrete or rock, such characteristics as compressive strength and physical stability are manifested to a significant degree. The sequence or method by which the CFS material is added and blended can be as important as the chemical agent(s) selected.

If rain or other surface waters cannot penetrate the treated waste mass, then the soluble salts contained within the waste mass will not provide a source of groundwater or other environmental contamination.

The following study was undertaken to determine the effectiveness of a commercially available solidification process, SOLI-BOND (R), a patented process developed by the Soli-Tech Corporation, in controlling the amount of salts and selected ions that could be leached from carefully prepared drilling waste samples. The effect of a plastic cover (raincap) as a barrier to percolating water was also examined.

Methods and Materials

An indoor lysimeter study was initiated in September, 1989 to study the effect of percolating water on the movement of soluble salts from prepared drilling wastes treated with a solidification process called SOLI-BOND. The study was conducted at Mobil's Stillwater, Oklahoma research facility.

Twenty four lysimeters were fabricated from 55 gallon steel drums. Cone shaped galvanized sheet metal funnels were installed in the drums 12 inches above the bottom. The cone tapered to two inches where it was welded to a steel pipe bib in the center of the barrel's base.

The barrel lysimeters were elevated off the floor to accomodate three quart capacity plastic trays to collect the drainage solution (leachate). Each barrel was lined with a heavy duty plastic to provide an impervious interior surface to the barrel lysimeters.

River sand, thoroughly washed and cleaned, was placed in the lysimeters to a level two inches above the top lip of the interior cone. Tap water was sprinkled into each lysimeter to settle the sand and the excess water was discarded.

The simulated drilling waste material was prepared by mixing a 100 pound sack

of dry gel (bentonite) with water into which had been dissolved five pounds of granular table salt (NaCl). Mixing was achieved using a conventional mortar mixer and adding enough freshwater to form a thick gel material. The calculated salt concentration for all samples was 35,000 ppm on a dry weight basis.

Fourteen batches of the prepared gel were mixed and stored in bulk until treatments were imposed. Treated samples were prepared by mixing the chemical solidifying agent at three different concentrations on a pound/cubic foot basis. The actual concentrations used are not disclosed in this report, in agreement with, and being the intellectual property of the Soli-Tech Corporation, owners of the patented process.

For the purpose of this study, the three treatment levels were described as "A" (being the lowest treatment level), "B" (being the next highest treatment level), and "C" (being the highest treatment level). Control samples receiving no solidification treatment were also prepared making a total of six sets of four treatment levels (0, A, B, & C).

In addition to the chemical solidification agent, each treatment was mixed with sieved, moist clay loam soil to duplicate a technique developed by the Soli-Tech Corporation to reduce the treatment and closure costs of drilling sumps in Kern County, California.

The mixture used consisted of one part soil material to five parts drilling waste material. Each treatment was mixed individually, by hand, using five gallons of prepared drilling waste material, the designated weight of the CFS material, one gallon of soil material, and fresh water added as needed to develop a thick paste consistancy.

The final mixed samples (treatments and controls) were each transferred to wooden forms which had been placed on top of the sand which partially filled the barrel lysimeters at this point in the experiment. The wooden forms represented a cube without a top or bottom of 1 ft. X 1 ft. X 1 ft. (inside demensions). The mixtures were then carefully packed into the forms to prevent air pockets or voids in the resulting solidified cubes of waste material.

The space between the inside wall of the lysimeter and the outside wall of the forms was then packed with wet sand so that the forms could be raised after each sample of the prepared waste material was properly placed in the forms.

This block forming and placement technique resulted in the creation of a cube shaped block which would be totally encased in an inert washed river sand media. In this manner, six complete sets of the four sample treatment levels were prepared.

The wooden forms were removed from the lysimeters after a 30 day "curing" period had been observed in which the blocks were allowed to set up. The remaining space in the lysimeters was then filled with washed river sand to

the top edges of the blocks. At this point, both treated and control samples were randomly selected to receive a plastic covering ("raincap"). The raincaps were evaluated as a part of the study protocol.

Pieces of 4 mil plastic were placed over the top and extended two inches down the sides of 12 randomly selected sample blocks (treatments and controls) to result in three replications of treated and control samples, with and without raincaps.

After the raincaps were installed, the barrel lysimeters were filled with washed river sand to within two inches of the top of the lysimeters. See "fig. 1" for an illustration of the barrel lysimeter design, functional use, and placement of the sample blocks.

On the same date that the preparation of the lysimeters and sample blocks was completed, the addition of "simulated rainfall" was commenced. This was achieved by placing a plastic water reservoir tray on top of the sand in each of the lysimeters and applying two separate one inch irrigations.

The plastic reservoir trays were prefabricated with 1/2 inch holes drilled in their center to allow the water to escape the trays into the sand directly above the buried sample blocks. The one inch irrigations drained from the reservoirs over an approximate two day period.

Following each two-inch irrigation, and just prior to the next irrigation, the drainage solution (leachate) was collected, the volume measured, and a sub-sample retained for laboratory analysis. Each set of leachate solutions was analyzed for electrical conductivity (E.C.) as well as chloride (Cl), Sodium (Na), and Calcium (Ca) concentrations. Calcium analysis was discontinued after the eighth two inch irrigation set because the concentration in the leachate was not significantly greater than the background irrigation water (tap water).

Analysis were performed by Oklahoma State University's Agronomic Services Laboratory. Results of the E.C. analysis were converted to total soluble salt values (TSS) by the standard conversion (660 X E.C.) expressed in micromhos/cm. The total amount of salts and specific ions collected from each irrigation was adjusted by subtracting the calculated amount of background salts naturally ocurring in the tap water used for the test irrigations (448 ppm TSS, 191 ppm Cl, 80 ppm Na, and 32 ppm Ca).

Treatment effects were evaluated statistically by comparing treatment means to a calculated least significant difference (LSD) after performing an analysis of variance for a 2 X 4 X 12 (including time) factorial arrangement of treatments.

Results and Discussion

Soluble Salts: Salts leached from the sample blocks (treated and controls) for each irrigation are reported in "table 1". These values show a very large initial quanity of salts leached from the control blocks with the first

two (combined) two-inch irrigations. This occurred even for the control sample blocks with protective raincaps. The results of the successive irrigation applications are graphically illustrated in "fig. 2".

By comparison, very small amounts of leachate were collected from the treated sample blocks until after four inches of water had been added. Apparantly a slight movement of water into the treated blocks occurred during the first two irrigation sets as the dry exterior surface of the treated blocks adsorbed the free water across their surface. A negative value for the "B" treatment with the raincap is a result of this initial "wetting up" phenomenon.

This effect is not, however, an artifact of the experimental procedure. It should also be expected to occur in field applications of chemical solidification and represents a positive aspect of the solidification process.

Subsequent irrigations continued to cause significantly large amounts of salt to leach from the control blocks until after a total of 16 inches of water had been applied (8th irrigation set). After this point, the amount of salt leaching from all the blocks (treated and controls) was small and significant differences (0.75%) were found for only the highest treatment rate "C".

The amount of salt leached from the treated blocks was consistantly less than the control blocks both with and without raincaps after each irrigation. The cumulative effect of treatment is shown by the percentage totals at the bottom of "table 1". These values clearly show the beneficial affect of the CFS process on reducing salt leaching from salt contaminated drilling wastes. Even the lowest treatment level "A" resulted in approximately a 100 % reduction in salt movement. Higher treatment levels resulted in progressively greater reduction in salt movement, as might be expected.

Covering the waste sample blocks with a raincap significantly reduced salt leaching by an overall average of 10 % of the total salt leached (27 % vs. 17 %). The "C" treatment was the most effective when combined with a raincap which reduced salt leaching from the waste mass from 46 % to 9 %, a five hundred percent decrease in salt movement. "Figure 3" graphically illustrates the cumulative effect of treatment versus non-treatment and further illustrates the data provided in "table 1".

Chlorides: The major concern in disposing of salt contaminated drilling wastes is usually focused on chlorides because the chloride ion is relatively easily leached into groundwater under certain conditions (groundwater lying in near proximity to the pit, permeable underlying soils, fractured underlying soils or rock). When this happens, groundwater use may be affected and responsible parties may be required to clean up the contaminated groundwater at great expense.

Results of chloride analysis of leachate from the lysimeters show a trend for Cl leaching similar to that described for soluble salts with regard to treatment effect. It should be noted, however, that Cl measurements were

direct analysis whereas soluble salts were estimated from electrical conductance of the leachate.

The greatest amounts of Cl were removed from the drilling waste sample blocks with the first irrigations leaching through the lysimeters. Each subsequent irrigation usually resulted in less Cl leached than for the preceding irrigation. Effectiveness of treatments is clearly seen by comparison of percentage Cl leached in the first few irrigatiom sets and percentage totals.

Without any CFS treatment, 31.9 % of the chloride initially present in the control sample blocks was leached out after 24 inches of irrigation or about one-third of the total available for leaching. Placing a raincap over sample blocks significantly reduced the total percentage of chloride leached to about two-thirds to one-half of that of the unprotected blocks.

The greatest reduction in chloride leaching resulted from CFS treatments at all levels applied in the study. The lowest treatment rate, "A", cut in half the amount of chloride leached from the waste blocks, with and without the existance of raincaps. Higher levels of treatment further reduced chloride leaching, but the change was not as dramatic.

Chloride leaching approached a zero level with the final irrigation sets for all lysimeters yet 85 to 95 % of the initial Cl was still available for leaching in the treated blocks. This 85 to 95 % represents an excellent control factor on the migration of chloride out of the treated waste mass, which is one of the primary objectives of pit waste CFS treatment.

A logical explanation for this excellent fixation/stabilization property exhibited in the treated blocks is that as a result of the solidification of the waste mass, water cannot physically percolate through the treated blocks, but rather passes across the top and down along the sides of the block.

In such a process, the only Cl leached from the buried solidified waste is that which diffuses across the side surface exterior and is then washed downward in percolating water. This process would also occur for Cl movement from the surface exterior of the top of the blocks without raincaps.

Since Cl migration by diffusion would appear to be limited to the outer exterior of the block surface, once Cl from this outer exterior had been removed by the erosion process, additional irrigations would be ineffective (as was subtantiated by the test data). Subsequent coring and analysis of the sample blocks confirmed the fact that the migration of Cl occurs, primarily, along the extreme outer exterior of the block.

Diffusion is dependent upon a carrier medium; in this case water. Unsolidified drilling wastes present the best medium for diffusion because they are solution saturated. By comparison, the treated blocks were, initially unsaturated and had a much lower free water content due to the chemical reaction of the CFS process and the formation of cementitious structures which takes place during the curing process.

Sodium and Calcium: The percentages of sodium and calcium leached from the blocks was observed and tabulated. These data are very similar to that shown for the chloride ion and do not provide any additional insight into the leaching mechanism or effectiveness of the treatments evaluated.

Summary and Conclusion

The compressive strength of the treated blocks appear to be more than adequate to support the bearing loads associated with post drilling, well head activities (e.g., well completions and equipment installation).

Solidification of salt contaminated drilling wastes using this CFS process at three different concentrations was effective in reducing leaching of salt two to five hundred percent. Without treatment, 46 % of the salt was leached from the blocks after 24 inches of simulated rainfall was applied. With treatment, the salt leached was reduced to 17 %.

With the lowest treatment level of "A", the leached salt was reduced to 23.6 percent of the total salt available for leaching. The next highest treatment level "B", further reduced salt leaching but the reductions were not large and only the highest treatment level "C" was statistically better than the "B" in reducing salt leaching.

Adding a raincap or plastic cover over the treated and control blocks further reduced the percentage of salt leached. The effect of a raincap on the "A" treatment reduced the salt leached to 17.5 % of the total salt available for leaching. Adding a raincap to the "B" treatment reduced the salt leached to a dramatic 10.5 %. Salt leaching was reduced to 9 % in the "C" treatment.

Of equal importance to total leachabilty control is the rate at which leaching occurs. If a constituent (e.g. salt) contained within a waste mass is released to the surrounding environment at a slow rate and low concentration, it presents no harmful affect to soil productivity or the quality of groundwater. Such a leaching process tends to lessen the harmful impact of buried wastes over time.

This study clearly indicates that the use of this particular chemical solidification process, does in fact reduce the amount and rate at which salt will migrate out of a salt contaminated waste mass treated with the process.

Using sand as the soil media in which to bury the sample blocks provides a very realistic and severe environment in which to test any CFS process. Sand, unlike more typical soils provides no appreciable impermeability or obstruction to the free flow of percolating fluids.

The use of plastic covers (raincaps) was found to be an effective tool in further reducing the amount and rates of salt leached. Likewise, without the early compressive strengths provided by chemical solidification, the proper and timely installation of a plastic raincap would be difficult or impossible.

TABLE 1

Effect of solidification and raincap treatments on total soluble salts* leached from prepared drilling waste by 12 successive two - inch irrigations.

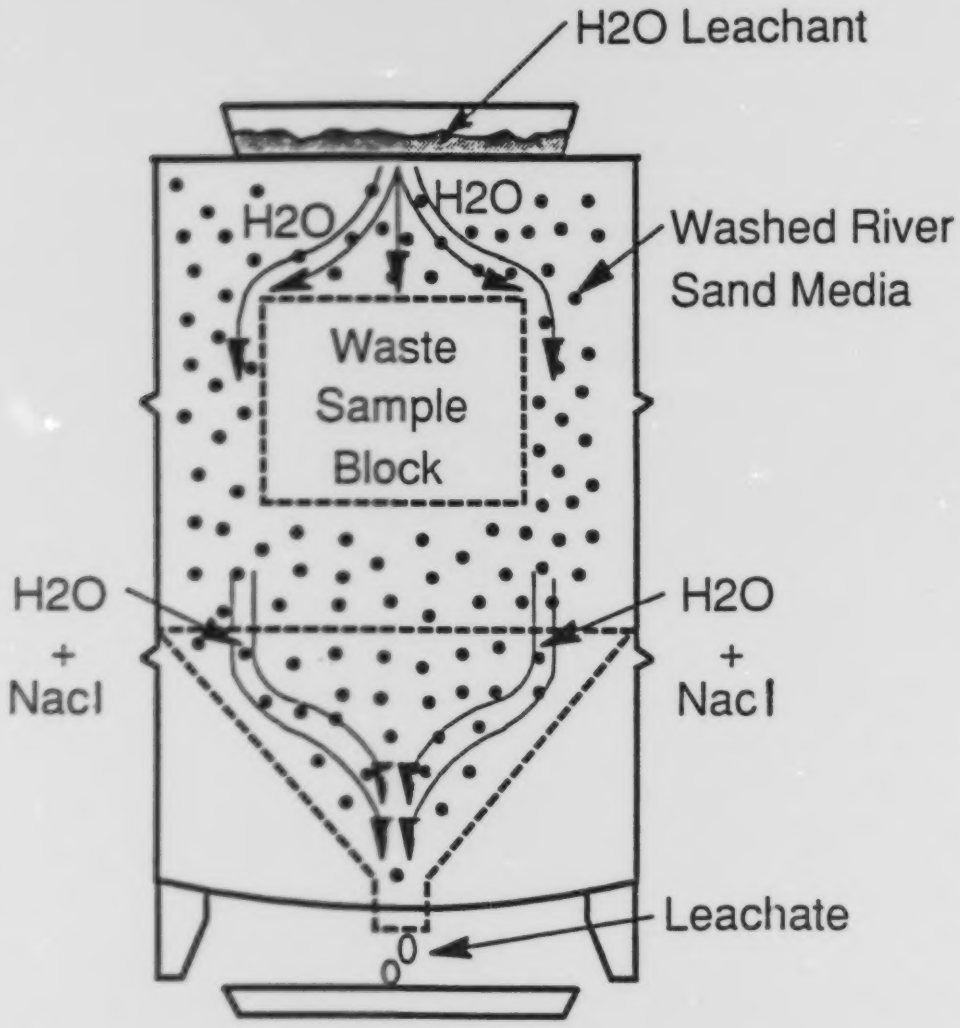
	Treatments***							
Soli-Bond	0	A	B	C	0	A	B	C
	No raincap				With raincap			
Irr.** Set	% of initial total							
2	11.8	1.25	0.20	0.18	9.88	1.71	-.21	0.37
3	7.29	3.37	2.81	1.98	3.57	1.87	1.18	0.75
4	3.38	1.63	2.37	1.40	1.40	1.27	0.75	0.44
5	4.26	2.97	2.74	1.96	2.30	1.94	1.27	0.91
6	3.44	2.37	2.06	1.79	1.78	1.49	0.93	0.92
7	6.13	4.53	4.97	3.85	5.06	3.20	2.70	2.35
8	2.46	1.71	1.68	1.60	1.72	1.24	0.97	0.72
9	2.15	1.56	1.66	1.16	1.53	1.24	0.83	0.58
10	1.78	1.53	1.41	0.95	1.48	1.14	0.65	0.55
11	1.87	1.45	1.49	1.60	1.63	1.18	0.77	0.76
12	1.52	1.28	1.20	1.23	1.12	1.19	0.63	0.67
Totals	46.1	23.6	22.6	17.7	31.5	17.5	10.5	9.0

* Values are an average of three replications. Least significant difference for comparison of values for each irrigation is 0.76 and for Totals is 4.12 at the 0.05 probability level.

** Two-inch irrigation set. Set one and two were combined.

*** Numbers after the heading Soli-Bond refer to the multiple treatment levels of Soli-Bond.

FIGURE 1
Design features and functional use of the barrel lysimeter.



L.C. Roberts, 1990

FIGURE 2

Effect of solidification and raincap treatment on the percentage of the total salts leached from prepared drilling waste by 24 inches of simulated rinfall.

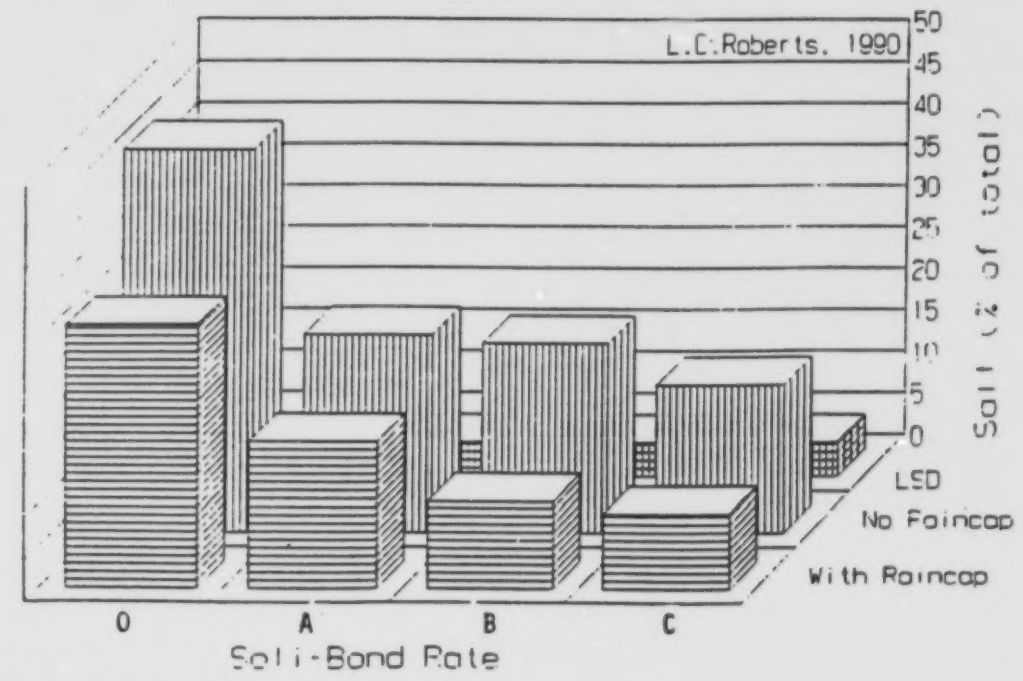


FIGURE 3

Effect of solidification and raincap treatments on salt leached from prepared drilling waste by 24 inches of simulated rainfall.

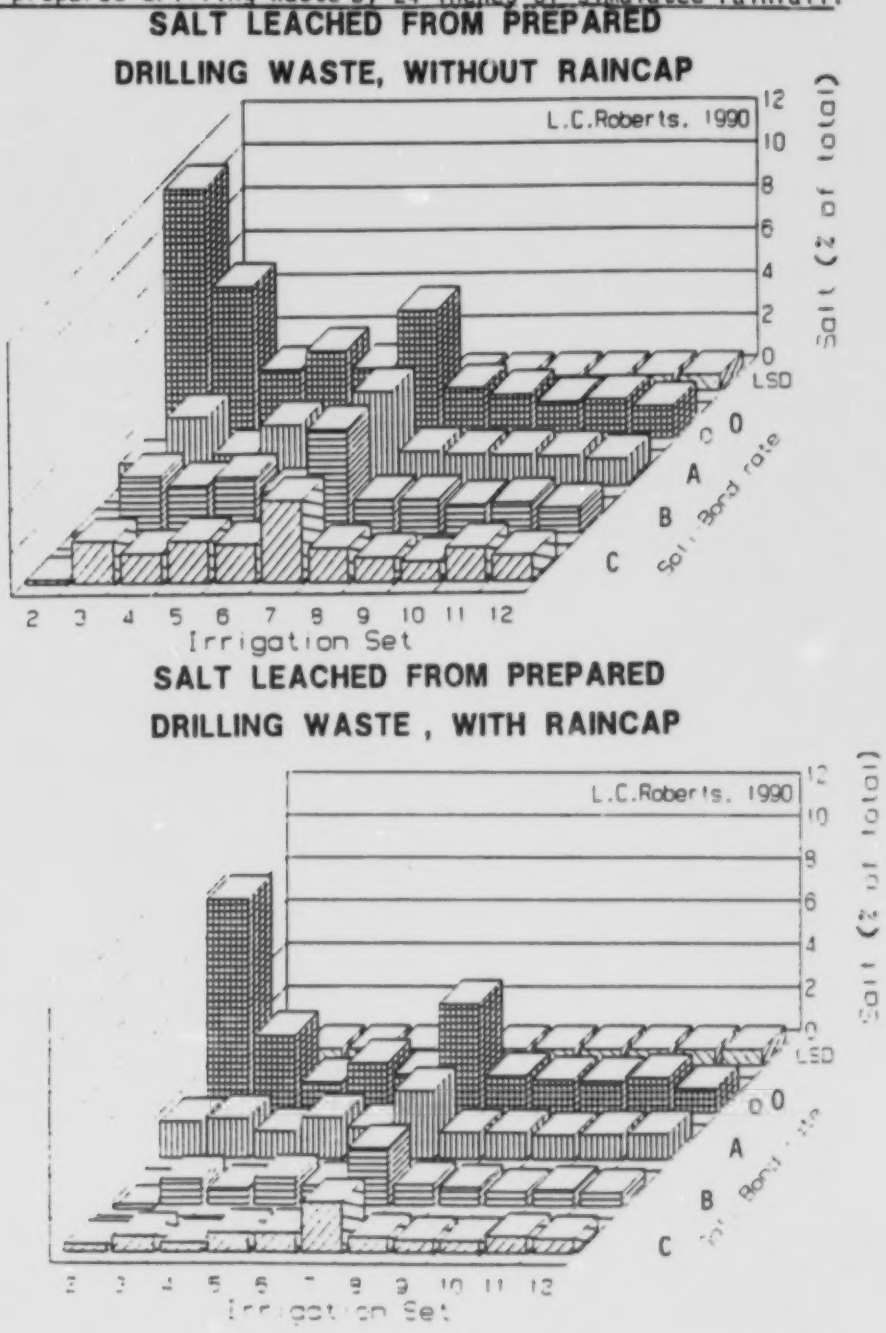
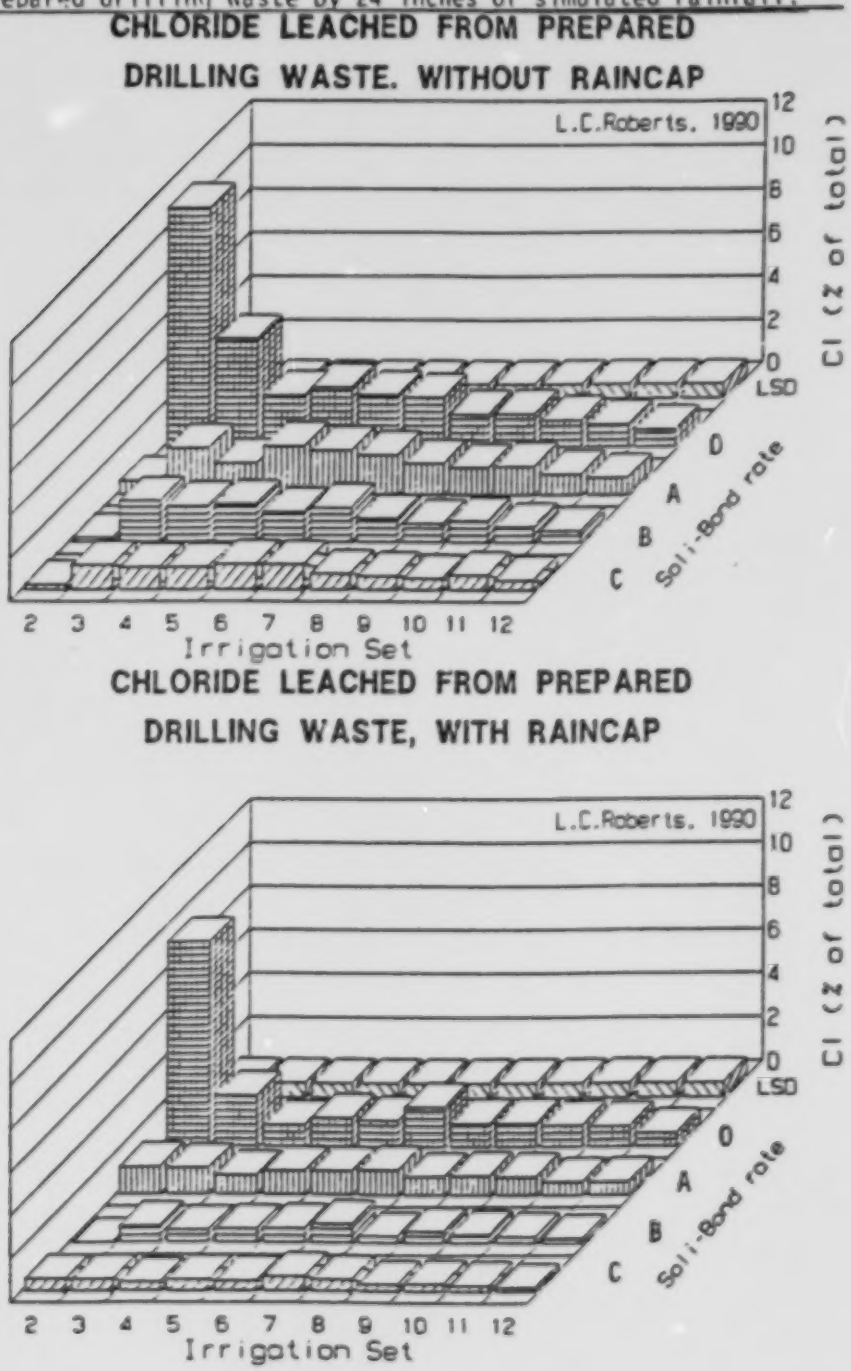


FIGURE 4

Effect of solidification and raincap treatments on chloride leached from prepared drilling waste by 24 inches of simulated rainfall.



SULPHUR BLOCK BASEPAD RECLAMATION PROGRAMS UNDERTAKEN AT THREE FACILITIES IN CENTRAL ALBERTA

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Introduction

Reclaiming soils that are heavily contaminated with elemental sulphur is specific to a small part of the oil and gas industry. Alberta produces 95% of Canada's elemental sulphur by converting the hydrogen sulphide present in sour oil and gas to elemental sulphur (1).

The majority of sour gas plants built prior to the mid 1970's stored elemental sulphur by pouring molten sulphur into large blocks. The block was poured on top of a basepad, which was usually formed from molten sulphur. Many of the basepads were poured directly onto soil, with minimal ground preparation.

There are approximately 105 elemental sulphur block basepads at 34 locations in Western Canada (2). These basepads range from a few hundred to fifty thousand square meters in area (3) and the total combined area of basepads is estimated to be 100 hectares. Since 1980 few, if any, new basepads have been established in Western Canada. Therefore, most basepads and associated blocks have been in place for at least ten years. As a result of increased sulphur sales and declining hydrocarbon reserves in older sour oil and gas fields, sulphur blocks are being depleted.

Once a sulphur block has been recovered, the basepad remains. Approximately 10% of the total sulphur inventory in Alberta is comprised of basepad material. The clean-up and reclamation of former sulphur basepad sites can be a difficult process, as up to 30% sulphur may remain in the soil once the initial clean-up phase is complete.

Once basepad clean-up is complete and the sulphur-contaminated soils are exposed, sulphur oxidation and, in turn, acidification will occur if the soil is left untreated. Former basepad areas must be neutralized and plant owners must satisfy regulatory authorities that the sites are environmentally secure.

Initial approaches to basepad reclamation, and a technical and economic evaluation of their recovery and reclamation have been previously published (4) (5). This paper is intended to provide an overview of the reclamation steps taken, and results of these steps, in the reclamation of three former basepad areas in central Alberta.

Background Information

Mobil Oil Canada began reclaiming former sulphur block basepad sites in 1987. These former basepad areas are located on agricultural land and are adjacent to sour gas processing plants. The principal objective of the reclamation program has been to establish a vegetation cover over the former basepads and surrounding areas.

When basepad sites were levelled prior to construction, the topsoil was usually stripped and molten sulphur poured directly onto the subsoil. Over the years, the stripped topsoil was often used for other purposes, leaving a compacted subsoil, low in nutrients and organic carbon, to be reclaimed when basepad recovery was complete.

The focus of a reclamation program is two-fold when there is no topsoil available: firstly, to neutralize the active and potential acidity generated from the oxidation of elemental sulphur; and secondly, to improve the subsoil so that it will be capable of sustaining plant growth. The degree to which the untreated soil will acidify depends on the amounts of elemental sulphur and natural calcium carbonate present, the extent and rate of sulphur oxidation, and the specific soil conditions.

It is well documented that acidic soils can be neutralized by the addition of calcium carbonate (limestone). There are several methods available to determine the amount of limestone required. The principal method used in Alberta is based on accounting for the total acidity generated if all the elemental sulphur present in the soil was oxidized. On the basis of molecular weight and stoichiometry, calcium carbonate is required in a ratio of three parts for every part of total sulphur detected in the soil. Therefore a soil that contained 20% sulphur, by weight, would require a limestone application of 60%, by weight, to the soil.

The second goal is to improve the structure, and organic carbon and nutrient levels of the subsoil so that it can support growth, assuming that the previously stripped topsoil is not available for replacement. In addition to the low levels of organic carbon, compaction is a serious growth-limiting problem. The weight of the sulphur block on the soil, combined with the heavy equipment operating in the vicinity of a storage area, leaves a severely compacted soil. Frequent and deep soil cultivation is not usually enough to ameliorate soil structure.

In order to improve the organic carbon content and tilth of the soil, organic matter in the form of animal manure and/or straw is added. Additionally, the sites are seeded with a forage mixture and/or cereal grain that can be ploughed down as green manure. The penetration of roots through the soil, resulting from vegetation establishment, also helps to improve soil structure.

From reclamation programs that have been undertaken to date, it is apparent that reclaiming a site that contains an average sulphur concentration of less than 5% will take at least three years, and more likely five to seven years. Therefore, plant owners are recognizing the merits of initiating liming programs immediately following basepad recovery. Prompt reclamation while the plant is still generating revenue allows the costs to be spread over a number of years prior to decommissioning the entire plant site.

Case Histories

Mobil Oil Canada is in the process of reclaiming former sulphur basepad sites at three facilities; Lone Pine Creek, Wimborne, and Harmattan. Reclamation activities were initiated in 1987 at both Lone Pine Creek and Wimborne facilities, and in 1988 at the Harmattan facility.

The first step taken at all three sites, once basepad recovery operations were completed, was to establish soil sampling sites that would be monitored annually. Soil samples were analyzed for pH, electrical conductivity (E.C.), and percent total sulphur. Based on the analytical results, initial liming programs were developed.

Table 1 presents a summary of the soil chemical parameters for each basepad site. It has been generally noted that the lower the soil pH value, the higher is the E.C. value. Soil pH values are generally lowest (i.e., most acidic) in soils that contain finely divided particles of elemental sulphur and inadequate levels of limestone. Total sulphur concentrations vary widely across a basepad site, making it difficult to initially apply appropriate levels of limestone to all areas.

The decrease in the number of sites monitored annually as the programs have progressed is due to the changing focus of the programs. Initially, a number of sites are established to determine the degree of sulphur contamination across the basepad area. As vegetation becomes established, the number of sites to be monitored annually are reduced and the focus of the sampling program is shifted towards determining the cause of bare spots, where vegetation has not become established.

All three sites were limed using powdered agricultural grind limestone, which was applied using a truck mounted pneumatic spreader bar. Initial limestone applications varied from 30-70 tonnes/acre, depending on the amount of sulphur present in the soil. A source of organic matter was also applied at each site.

TABLE 1

Summary of selected soil chemical parameters at three Mobil Oil Canada former sulphur basepad sites. Data are expressed as mean values ± standard deviations.

	pH			Electrical Conductivity (dS/m)			Total Sulphur (%)		
Site	1987	1988	1989	1987	1988	1989	1987	1988	1989
Lone Pine Creek (n=9)	4.5±2.1	5.9±1.8	5.3±1.4	7.3±3.3	7.7±7.7	7.1±2.8	0.5±0.5	1.7±1.6	N/A
Wisborne North Pad (n=23)	3.9±1.9	5.6±1.6	4.1±2.3[1]	13.5±7.2	7.8±2.5	13.6±9.7[1]	6.5±9.2	5.1±6.9	6.5±4.9[1]
Wisborne South Pad (n=15)	5.7±1.8	6.6±1.2	5.3±1.9[2]	10.2±3.7	7.6±1.6	10.8±6.4[2]	7.8±4.7	4.8±4.1	6.2±4.6[2]
Harmattan (n=5)	N/A	7.4±0.7	7.7±0.2	N/A	5.5±0.7	6.0±0.8	N/A	1.2±1.4	4.7±5.1

N/A not available.
1 n=10.
2 n=8

Once the initial liming programs were carried out, the Lone Pine Creek and Wimborne basepad areas were seeded in 1987. There had been no growth on these sites since the basepad recovery programs, and poor drainage and water ponding were problems. The objective of the seeding program was to establish a plant cover, thereby helping to improve soil tilth and the soil's water storage capacity. Yellow sweet clover was seeded because of its biennial nature, its ability to fix nitrogen, its deep tap root for penetrating compacted soil, and its ability to establish on clayey, alkaline or sodic soils. It is also a good green manure crop and so was selected for its ability to increase organic matter levels on these sites. Barley and fall rye were seeded as cover crops at Lone Pine Creek and Wimborne, respectively.

Initial germination at Lone Pine Creek was better than expected. Growth at the Wimborne site was poor, but it is thought that this was partly due to seeding methods and the weather.

Following the initial yellow clover and cereal seeding program, there were bare areas at both Lone Pine Creek and Wimborne, where no vegetation became established. These areas were mapped and the soil was sampled. Analytical results indicated that the majority of the areas were both acidic and contained high levels of soluble salts. Additional liming programs were carried out in both 1988 and 1989 to counteract the acidity.

The Harmattan site was seeded during the first summer following basepad recovery (1989), but little growth was achieved. Upon review of the soil analytical data, it was concluded that a low level of organic carbon, and not the sulphur contamination, was the principal chemical limiting factor. It was concluded that soil compaction was also limiting plant growth. Yellow sweet clover was not used initially at Harmattan, although it will be included in the 1990 seed mixture.

The second part of the seeding program focused on establishing plants on a more long-term basis, rather than the green-manure emphasis of the initial seeding program. The 1989 seed mixture selected for all three basepad sites included plants that have a tolerance for high salt levels and/or low soil pH values, and an ability to grow on poorly drained, clayey soils.

Six row barley, which is fairly salt tolerant, was seeded in one direction. A forage mixture composed of alsike clover, alfalfa, tall wheatgrass, and brome grass was then seeded in a perpendicular direction. Alsike clover and alfalfa were selected for their ability to fix nitrogen. Alsike clover was also selected for its ability to grow in poorly drained, clayey soils, and its ability to tolerate both moderately acid and alkaline soils (6). Alfalfa was selected because of its sensitivity to acidic soils, and its usefulness to indicate soils which were not acidic.

Brome grass was selected because of its ability to establish quickly and to adapt to a wide range of soil conditions. Brome grass is reported to be fairly saline tolerant, but to have a poor tolerance of acid soils (6). Tall wheatgrass was selected because of its ability to grow on soils that range from being well drained to where the water table is within a few centimeters from the surface. It is also reputed to be "the most salt tolerant of all cultivated grasses" (6).

It was felt that this forage mixture represented a combination of plants that should be able to establish over most of the basepad areas. The use of plants with different tolerances to such factors as moisture conditions, and soil acidity and salinity should allow visual observations of the probable cause of no growth. Further sampling and treatment of these areas should improve reclamation success.

Barley established well in 1989, at both Lone Pine Creek and Wimborne sites. The forage mixture was slow to germinate, but growth improved by late August, 1989. The summer of 1989 was hot and dry, with small amounts of precipitation scattered throughout the year. However, the spring and summer of 1990 were very wet and forage growth improved dramatically at both sites.

Yield samples were taken in the late summer of 1989 from both Lone Pine Creek and Wimborne. Samples were taken using a 0.5 m^2 sampling hoop, and plants were cut at the soil surface. The principal plant cover was barley, and dry matter yields ranged from no growth to 1.6 tonnes/acre. Based on the Alberta Hail and Crop Insurance Corporation long term averages, a dry matter yield from barley fields in these two areas would be approximately 2.5 tonnes/acre. Therefore, the yields recorded for the best growth on the basepad sites were lower than those expected from average fields in the regions.

Based on the data from the bare spot sampling program in 1989, additional limestone was applied in the fall of 1989. All bare spots were then re-seeded in the summer of 1990. Initial indications are that germination will be fairly good. More so than any other year, the bare spots are clearly delineated. It is interesting to note that tall wheatgrass is the last plant to survive around the perimeter of the bare areas. Further sampling programs this year will indicate whether the bare spots are the result of acidity, salinity, or a combination of the two.

Table 2 summarizes the reclamation steps that have been undertaken to date at each basepad area.

General Observations on Reclamation Program Success

A number of observations have been noted during this reclamation program. The first of these is that sulphur levels across a site are highly variable. Although the average levels for each site are quite low, the range of values is wide. Without sampling on a very small scale grid, it is difficult to accurately determine sulphur levels. Because of the variability of sulphur levels in the soil, repeated liming and seeding operations are required to treat the bare spots.

TABLE 2

Summary of reclamation steps undertaken at former sulphur basepad sites of three Mobil Oil Canada facilities.

Year	Area (ha)	Amount of Limestone Applied (tonnes)	Amount and Type of Organic Matter Applied	Type of Seed Used	Estimated Annual Cost ($)	Estimated Annual Cost/ha ($)
[illegible]						
1987	3.4	363	—	Barley & yellow sweet clover	23,690	6,967
1988	3.4	103	8 round bales of yellow sweet clover	Barley & yellow sweet clover	18,000	5,294
1989	3.4	71	—	Barely & forage mixture	13,000	3,825
1990	3.4	ongoing	—	Barley & forage mixture on bare spots	ongoing	ongoing
[illegible]						
1987	3.2	437	—	Fall rye & yellow sweet clover	15,000	4,687
1988	3.2	68	330 tonnes of manure and straw	—	11,000	3,448
1989	3.2	56	—	Barely & forage mixture	9,000	2,815
1990	3.2	ongoing	—	Barley & forage mixture on bare spots	ongoing	ongoing
[illegible]						
1988	3.4	145	—	—	10,625	3,125
1989	3.4	23	—	Barley & forage mixture	7,000	2,060
1990	3.4	ongoing	750 tonnes of manure	ongoing	ongoing	ongoing

Secondly, some site preparation work is generally required as part of the reclamation program. This includes landscaping in order to improve site drainage, and rock-picking. It is important that acidic materials not be buried during landscaping. It is most efficient to leave the sulphur-contaminated soil on the surface where limestone can be easily mixed with it. This allows for the opportunity to neutralize areas that re-acidify over the years.

Thirdly, the areas that are re-acidifying and not supporting plant growth generally exist around the perimeter of where the sulphur block was located. Elemental sulphur would have been continually deposited on the soil surface as a result of block operations and spills. Another area where bare spots are commonly located are where piles of sulphur-contaminated material, remelt pits or equipment were located during basepad recovery operations.

Another observation is that the methods used for seeding and the types of seeds used are crucial to the success of the program. The cover established when seed was broadcasted was not optimal, and a seed drill is now used. Because of the relatively small size of the sites and the even smaller size of the bare spots, eight foot wide farm equipment is used. This allows treatment and seeding of the bare areas without disturbing the rest of the site that is supporting growth.

Finally, as the reclamation program progresses, a shift in focus is evolving. Once the initial site assessments are made and limestone has been applied a sufficient number of times, there is a shift from simply managing soil pH levels to the long term development and maintenance of adequate soil structure needed for agricultural production.

Summary

Reclamation of these sites requires the application of a number of scientific principles to a very specific set of circumstances. As stated earlier, the aerial extent of former basepad sites is not large, but the ramifications of not treating them could be great. Unchecked sulphur oxidation from these sites could lead to groundwater and neighboring soil contamination.

The approach taken by Mobil Oil Canada has been to initially apply limestone in a 3.1 ratio based on the average sulphur concentration of the former basepad site. Areas known to be more contaminated receive additional limestone. The former basepad sites are then seeded and growth is monitored. Once the bare spots become evident, additional soil sampling is carried out. Amendments are applied to the bare spots as necessary and the areas are re-seeded.

Monitoring of reclamation treatments at all facilities provides useful information. Annual monitoring is a good method of obtaining an overview of general soil chemical conditions of a former basepad site. Sampling individual bare spots allows determination of the cause of the bare spot, thus allowing remedial action to be taken.

The major management issues in reclaiming these types of sites are working out the logistics of accomplishing the required work, and ensuring that the site is monitored and actively treated until successful reclamation is achieved.

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A TC MODEL ALTERNATIVE FOR PRODUCTION WASTE SCENARIOS

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Introduction

The Environmental Protection Agency has recently promulgated the Toxicity Characteristics (TC). The rule [1] establishes regulatory levels for approximately 40 organic chemicals based on health-based concentration thresholds and a dilution-attenuation factor that was developed using a subsurface fate and transport model. In summary, any waste containing any of the 40 organic chemicals discussed in the rule at a concentration which exceeds the maximum allowable leachate concentration is considered to be hazardous and cannot be disposed of in a municipal landfill. The EPA has specifically exempted Exploration and Production (E & P) wastes from the TC rule, mainly due to economic considerations. Some states, however, may adopt the TC rule to regulate E & P wastes, and it is conceivable that the EPA will repeal its exemption for those wastes.

The objective of this study was to develop a toxicity modeling scenario to represent reasonable waste management practices for E&P wastes. The modeled scenario, on-site management with benzene as the primary constituent, would be used as an alternative to EPA's current municipal co-disposal scenario for E&P wastes. The scenario used by EPA in the TC rule assumes steady-state conditions and infinite source strength, non-biodegradable constituents, and national distributions for some of the model parameters. The final toxicity rule dictates a maximum allowable leachate concentration which is 100 times the health-based maximum allowable concentration for the TC organics. The E & P wastes scenario varies from that used by EPA in two main areas: (1) transient conditions are assumed for contaminant transport in the unsaturated and saturated zones; and (2) data about geometric configurations of disposal facilities, waste volumes, concentrations of benzenes in oily wastes, and distributions of E & P activity over the U. S. were obtained from the E & P wastes database compiled by the American Petroleum Institute.

The TC Model - EPACML

The Environmental Protection Agency's Composite Landfill Model (EPACML) simulates the movement of contaminants (through the unsaturated and saturated zones) leaching from a hazardous waste landfill. The composite model consists of a steady-state, one dimensional numerical module that simulated flow in the unsaturated zone. The output from this module, seepage velocity as a function of depth, is used as input by the unsaturated zone transport module.

The latter simulates transient, one-dimensional (vertical) transport in the unsaturated zone and includes the effects of longitudinal dispersion, linear adsorption, and first-order decay. Output from the unsaturated zone modules, i.e., contaminant flux at the water table, is used to define the gaussian-source boundary conditions for the transient, semi-analytical saturated zone transport module. The saturated zone module includes one-dimensional uniform flow, three-dimensional dispersion, linear adsorption, lumped first-order decay, and dilution due to direct infiltration into the ground water plume [2]. A shematic of the waste facility and leachate migration as simulated using the EPACML model is shown in Fig. 1.

The uncertainty in the medium and environment-specific parameters in the unsaturated and saturated zones is quantified in EPACML using a Monte Carlo Simulation technique. Several of the model parameters can be input as statistical distributions, and the model is run for many iterations (around 2000) to obtain a cumulative frequency distribution of the concentration at a receptor point, usually a monitoring well. The model output is used to back-calculate the maximum allowable concentration of a chemical constituent at the point of release (i.e., below a landfill) such that the receptor well concentration does not exceed a health-based (maximum) threshold level. The Dilution Attentuation Factor (DAF) is defined as the reciprocal of the computed normalized concentration at the receptor well. The product of the DAF and the health-based maximum allowable concentration equals the maximum allowable leachate concentration at the facility.

Previous studies [3, 4] indicated that there are several weaknesses in EPA's approach and modeling scenario. Mainly, use of the steady-state conditions in the modeling scenario masks the attenuation that would be expected through the unsaturated zone (except when biodegradation in the unsaturated zone is simulated). In addition, the steady-state assumption produces results which are inconsistent with common-sense waste management practices. For example, when the effect of seepage velocity in the model is considered under steady-state conditions, a hydrogeologic environment with high seepage velocity such as glacial outwash would have higher allowable source concentrations than an environment with low seepage velocity, such as an unconsolidated shallow aquifer.

For the purposes of this study, the parameters of interest which were used to develop an alternate modeling scenario for E & P wastes were mainly the source parameters and the hydrogeologic properties of the aquifer. The source parameters in EPACML include the infiltration rate from the landfill, the area of the waste disposal unit, the duration of the source, the spread of the contaminant source, the recharge rate, a source decay constant, the initial concentration at the landfill, and the length and width scales of the facility. The source parameters which are used in EPA's modeling scenario are listed in Table 1 with a brief description of the type of distribution used for each parameter. The hydrogeologic parameters which were used to develop the E & P wastes modeling scenario are discussed later in this paper.

The API 1985 Production Waste Survey

Exploration and production wastes can be divided into three basic categories: drilling wastes, produced waters and other associated wastes. Drilling fluids consist primarily of drilling muds, cuttings from the well bore and chemicals added to drilling fluid systems to improve mud

properties. Produced water consists of formation water plus chemicals added for treatment. Associated wastes consist of small volumes of waste such as tank bottoms and produced sands generated in conjunction with drilling and producing operations.

The American Petroleum Institute (API) conducted a study on wastes associated with the exploration for and production of oil and natural gas. The goals of the study were to develop independent estimates of waste volumes and sources and to analyze waste management practices, waste disposal methods, waste characteristics and pit closure practices [5]. A survey questionnaire was prepared by API and mailed to representatives of the API member companies. The production waste survey was divided into several parts: (1) Part I- Drilling Waste; (2) Part II- Associated and Other Wastes; and (3) Part III- Produced Water (includes a supplement).

Part I of the survey was designed to estimate the source, volumes and disposal practices of drilling fluids for all wells drilled in 1985. The sample contained 659 wells (about 1% of all the wells drilled in 1985). Typical information provided on each well included the location of the well by State and County, the total depth of the well, total fluid volume, total volume of drill cuttings discharged into the reserve pit, the reserve pit dimensions, and the methods that were used to dispose of the reserve pit contents.

Part II was designed to estimate the volume of other wastes associated with the exploration, development and production of oil and gas resources such as sludges, tank bottoms, oily debris, waste waters, and untreatable emulsions. About 141 responses on volume estimates were listed from 25 different companies. The data in Part II of the E & P database provided estimates of the volumes of associated wastes listed by State and operator (or member company). Part II also included the percentages of those volumes which were disposed of by several methods: recycling, spread on roads, land spread, incineration, onsite pit, onsite burial, offsite commercial facility, and other methods. The methods of disposal of interest in this project include: land spread, onsite pit, and onsite burial. The data in Part II indicated that 17% of associated wastes were disposed of by those three methods [6]. Unfortunately, Part II of the database did not include any information about the specifics of the three disposal practices for associated wastes. As a result, it was not possible to develop a TC modeling scenario for associated wastes.

The data in Part III consisted of state and industry records of produced water volumes. A supplement included in the surveying process was also used to estimate volumes of produced water. The estimates of produced water from the supplement were based on 170 responses which accounted for 51% of the total onshore U. S. production of crude oil. The data in Part III and the supplement of the API E & P wastes study indicated that produced waters are for the most part disposed of by salt water disposal, enhanced oil recovery, and NPDES discharge. In this case, it was not necessary to develop a TC modeling scenario for produced waters.

Statistical Analysis of the API 1985 Production Waste Survey Data

The data in Part I of the E & P database were used to develop the E & P wastes modeling scenario. The majority of drilling wastes are disposed of in reserve pits. The contents of the reserve pit are subsequently disposed of by several methods which include hauling offsite, onsite burial, land spread, discharge to the surface, evaporation, and injection down the annulus. The database did

not include detailed information on the contents of the reserve pits, and their operational lifetime. A significant percent of the reserve pits are lined, however, the EPACML modeling approach assumes unlined municipal landfills. For the purposes of this study, no distinction was made between lined and unlined pits. In essence, the most significant parameters in the database which were relevant to this project were the geometric configurations of the reserve pits, waste volumes, and the distribution of E & P wastes activity over the U. S.

The reserve pit geometric configuration data were analyzed using a commercially available statistical program [7] to develop statistical distributions for area, length, width, and depth of the reserve pits. The most appropriate distribution for the four parameters was the lognormal distribution (Fig. 2). The data for the area of the reserve pit were also fit with an exponential distribution.

Linking the E & P Wastes Database to a Hydrogeologic Database

In a related, but separate effort (funded by the API), a survey of 400 sites across the nation [8] was used to develop a national database for the main hydrogeologic parameters used in the TC model (hydraulic conductivity, seepage velocity, depth-to-water, penetration depth). The survey data, referred to as the **H**ydro**G**eologic **D**ata**B**ase (HGDB), were used to develop national averages for each of the parameters, and to develop parameter distributions for subsurface environments with similar hydrogeologic characteristics. The grouping procedure of the data was based on the DRASTIC system [9] which divides the U. S. into *Ground Water Regions*. Each of the *Ground Water Regions* in DRASTIC is further divided into *Hydrogeologic Settings* (144 in all). Due to the lack of sufficient data for some of the 144 settings, the data in the HGDB were grouped into 12 *Hydrogeologic Environments* which are composed of the 144 originally discussed in DRASTIC. The DRASTIC *Ground Water Regions*. and the HGDB *Hydrogeologic Environments* are listed in Table 2. The HGDB parameters which relate to the EPACML model are the saturated thickness of the aquifer, the hydraulic conductivity, the seepage velocity, the gradient, and the penetration depth of the source into the saturated zone. These five parameter distributions were utilized in developing an E & P wastes modeling scenario.

For the purposes of this study, the E & P wastes database was linked to the HGDB in order to utilize some of the HGDB parameter distributions. The reason for this is that the national average parameter distributions used by the EPA (which were found to be very similar to the HGDB national distributions) are too generic and do not reflect the characteristics of specific hydrogeologic environments. Newell et al. [8] and Hopkins [10] conclude that different results are obtained with the TC model when the HGDB parameter distributions are utilized in the analysis.

The first approach attempted to correlate the EPA defined production regions to the HGDB. This approach was not realistic, however, because it did not reflect the location of the actual producing fields. The adopted approach for this study involved correlating the Oil & Gas producing regions to the DRASTIC *Ground Water Regions*. The location of each of the wells in the database was correlated to a DRASTIC *Ground Water Region*. In some cases, the well was considered to belong to two regions because of inaccuracies in the mapping procedures. The results from the correlation study indicated that for the most parts, the reserve pits were mostly located in the High

Plains, Nonglaciated Central, Alluvial Basins, Atlantic and Gulf Coastal Plains, Colorado Plateau & Wyoming Basin, and Glaciated Central DRASTIC regions.

Modeling Results

A sensitivity analysis was conducted using EPA's scenario to determine the effects of changing the source configuration data on the modeling results. The data in Table 3 show the DAF results for a number of the sensitivity runs. It can be seen from Table 3 that using the geometric configuration data from the E & P wastes database changes the DAF significantly from EPA's scenario (there are several ways that one can enter the geometric configuration data into the EPACML model). Basically, the DAF's ranged from about 176 to 255 compared to EPA's scenario DAF of 8.

An attempt was made to develop the E & P waste scenario using a Monte Carlo transient modeling approach, however, the runtime for those conditions was quite long (exceeds 48 hrs in some cases). In the interest of time, and for the purposes of examining the sensitivity of the model to some of the parameters using transient conditions, it was decided to utilize the transient deterministic option in the model. The deterministic option in the model replaces the statistical distribution for any parameter with a single value, usually the mean of the distribution.

Some of the results from the transient deterministic model runs for two of the *HGDB Hydrogeologic Environments* (alluvial basins, valleys, and fans, and river alluvium with overbank deposits) are shown in Table 4 (due to the large number of DRASTIC *Regions* and *HGDB Environments*, only a few are discussed in this paper). The E & P data for the Alluvial Basins DRASTIC region was used in this case because it had the largest number of reserve pits in the database. The transient model results are shown in Table 4 for two points in time: 100 years and 10,000 years. The first two runs listed in Table 4 consist of EPA's scenario run, and EPA's scenario with the geometric configurations of E & P drilling reserve pits for benzene. It is noted from the first two runs in Table 4 that the time-to-steady state is in excess of 100 years.

The other runs listed in Table 4 mainly show the sensitivity of the transient assumption model results to changes in the aquifer parameter distributions obtained from the HGDB. The parameters that had the most effect on model results were the saturated thickness, the gradient, the hydraulic conductivity and the seepage velocity. This effect varied in magnitude between the two HGDB environments presented, with it being more pronounced in the river alluvium environment. The runs listed in Table 4 also indicate that for some cases, the transient concentrations at 10,000 years are not equivalent to the steady-state concentrations. The cause for this was not investigated.

In summary, the model results indicated that utilizing the E & P wastes database geometric configurations for reserve pits and the parameter distributions from the HGDB could potentially yield much larger DAF's than EPA's modeling scenarios.

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TABLE 1
Source Specific Parameters for EPACML

Variable Name	Units	Derived Variable	Default Values				
				Parameters		Limits	
			Distribution	Mean	Std Dev	Min	Max
Infiltration rate	m/yr	No	6	0.007002	0.007002	0.0000254	0.668
Area of waste disposal unit	m^2	No	9	4.21	2.16	-0.884	12.3
Duration of pulse	yr	No	0	1E+30	3	0.1	1E+30
Spread of contaminant source	m	Can be derived	-1	50	0	0.001	60000
Recharge rate	m/yr	No	6	0.0076	0.0076	0.0000254	0.668
Source decay constant	1/yr	No	0	0	0	0	10
Initial concentration at landfill	mg/l	No	0	1	0.01	0	10
Length scale of facility	m	Can be derived	-1	100	1	1	100000
Width scale of facility	m	Can be derived	-1	100	1	1	100000

Distribution Types	Code
Constant	0
Normal	1
Lognormal	2
Exponential	3
Uniform	4
Log10 uniform	5
Empirical	6
SB Distribution	7
GELHAR Distribution	8
AREA Transformation	9

TABLE 2
List of DRASTIC Ground Water Regions and HGDB Hydrogeologic Environments

Drastic Ground Water Region	HGDB Hydrogeologic Environment
Alaska	Alluvial Basins, Valleys, & Fans
Alluvial Basins	Bedded Sedimentary Rock
Atlantic & Gulf Coastal Plains	Coastal Beaches
Colorado Plateau & Wyoming Basin	Metamorphic & Igneous
Columbia Lava Plateau	Outwash
Glaciated Central Region	River Alluvium with Overbank Deposits
Hawaii	River Alluvium without Overbank Deposits
High Plains	Sand & Gravel
Nonglaciated Central Region	Solution Limestone
Northeast & Superior Uplands	Till & Till Over Outwash
Riedmont & Blue Ridge	Till Over Sedmentary Rock
Southeast Coastal Plains	Unconsolidated and Semi-Consolidated
Western Mountain Ranges	Shallow Surficial Aquifers

Table 3
Results from EPACML Steady-State Monte Carlo Runs

Run Description	85th C/Co	85th DAF
EPA Scenario for Benzene	1.25E-01	8
API area distrib.-lognormal; L,W derived	5.67E-03	176
API A, L, W -lognormal distributions	3.83E-03	261
API area distrib-expon. L,W derived	5.98E-03	167
Area-transform lognormal, L,W derived	5.47E-03	183
Area, L,W- transform lognormal	3.92E-03	255

Table 4
Results from EPACML Transient Deterministic Runs

Run Description	85th C/Co 100 years	85th C/Co 10000 years	85th C/Co Steady State
EPA Scenario for Benzene	9.18E-23	2.26E-06	2.26E-06
E&P L, W, A transform lognormal	4.02E-21	3.45E-04	3.45E-04
Alluvial, Saturated Thickness	4.02E-21	6.87E-04	6.87E-04
Alluvial, Gradient	1.60E-20	1.35E-03	1.35E-03
Alluvial, Hydraulic Conductivity	1.73E-22	1.50E-05	1.50E-05
Alluvial, Seepage Velocity	5.17E-10	1.59E-06	1.59E-06
Alluvial, Penetration Depth	5.45E-21	3.45E-04	3.45E-04
River, Saturated Thickness	1.35E-20	8.82E-04	2.40E-03
River, Gradient	3.57E-20	1.16E-03	2.92E-03
River, Hydraulic Conductivity	1.06E-10	1.09E-07	3.00E-07
River, Seepage Velocity	1.12E-10	1.15E-07	3.16E-07
River, Penetration Depth	6.22E-21	3.45E-04	3.45E-04

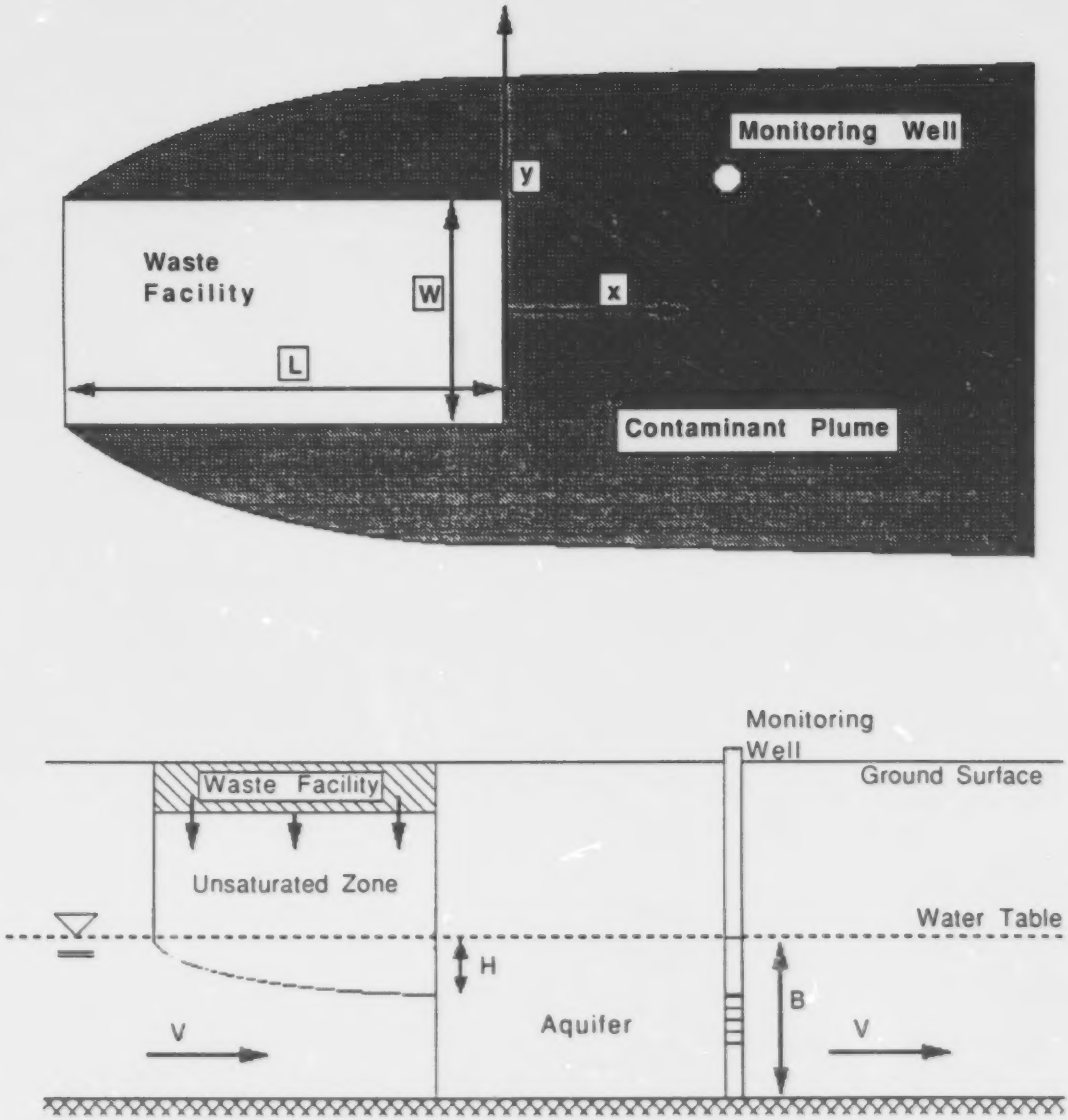

Fig. 1. A Schematic of the Waste Facility Source Boundary Condition and Leachate Migration Through the Unsaturated and Saturated Zones for EPACML

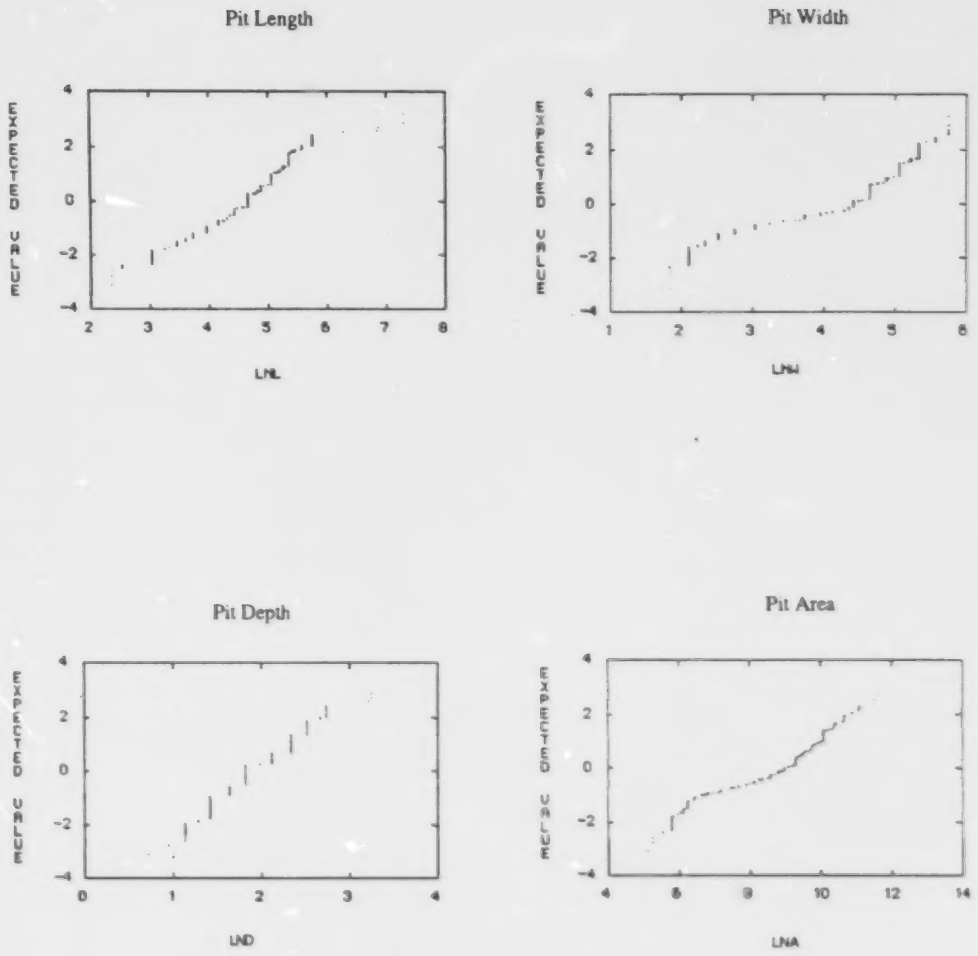

Fig 2. Lognormal Distributions for Reserve Pit Dimensions

THE APPLICATION OF CONCENTRIC PACKERS TO ACHIEVE MECHANICAL INTEGRITY FOR CLASS II WELLS IN OSAGE COUNTY, OKLAHOMA

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ABSTRACT

The Environmental Protection Agency's Region 6 policy of working with private industry to develop new methods for remedial action resulted in the adaptation of the concentric packer to the role of providing mechanical integrity of the casing in Class II wells in early 1987. Prior to this time, oil companies in Osage County, Oklahoma whose wells failed the mechanical integrity test as a result of holes in the casing had the basic remedial action options of squeezing, cementing new casing inside the old casing, backing off and replacing the bad casing joints if well conditions permitted or plugging and abandonment if no production zones were available for recompletion.

The use of a concentric packer to seal off casing holes, collar leaks and old perforations therefore allowing the well to demonstrate that there is no significant leak in the casing per 40 CFR Part 147.2912 (1) has proven to be a successful alternative to the basic remedial action options if well conditions are favorable. As of March 1989, there have been 26 concentric packers run in Class II wells in Osage County, Oklahoma with 20 of the wells passing the EPA mechanical integrity test as a result. The use of this tool has also allowed operators to realize a significant cost reduction in their workover operations with little of the risk to the wellbore that is inherent in other operations such as squeezing cement or running a liner.

INTRODUCTION

The Environmental Protection Agency's Region 6 has direct implementation of the Osage UIC Program as set forth in the Safe Drinking Water Act of 1974. The Osage UIC Regulations (40 CFR Part 147, Subpart GGG) require that all injection wells demonstrate mechanical integrity by December 30, 1989 and at least once every five years thereafter. The Osage UIC Program

regulates approximately 3500 injection wells. These wells range in age from new wells to those drilled around the turn of the century. Many of these wells require some type of remedial action in order to pass the mechanical integrity requirements as set forth in 40 CFR Part 147.2912 (1).

The basic casing repair options have historically been squeeze cementing, running and cementing a smaller size casing or tubing as a liner inside the old string, backing off the bad joints and replacing with new ones or plugging and abandonment if the well was not salvageable.

Squeezing old casing or running a liner are relatively expensive operations in an mature producing area where economics are already tight. Replacement of bad casing with a backoff operation is often unfeasable due to the age of the well and the initial completion practices used. In addition, there is always a certain amount of risk involved as the type of stresses inherent in these operations can worsen the condition of the casing or even cause the well to be junked. Plugging and abandonment of a Class II well can impose an economic burden on a lease due to a loss of injection capability as well as the cost of the abandonment operation.

In an effort to find an alternative method of casing repair that would be effective, economical, easily applied as well as relatively low risk, the concept of using a concentric packer was developed and applied to these Class II wells.

CONCENTRIC PACKER

The concentric packer, sometimes refered to as a scab packer, is not a new tool. It has been in use for many years as a production tool in wells to shut-off an influx of water above a production zone that would either kill the well or render it uneconomical to produce. This packer has also been used to shut off a gas influx to the wellbore that was interfering with production operations.

The concentric packer is ideally suited to the task of casing repair on Class II wells as it meets the regulatory requirements for establishing mechanical integrity under 40 CFR Part 147.2912 (1). These requirements are met since there is an annulus between the tubing and the packer assembly that allows hydraulic communication from the wellhead to the injection packer at the bottom of the tubing. This type of construction allows the mechanical integrity tests to demonstrate that there are no significant leaks in the casing, tubing and packer as long as the bad section of the long string casing is isolated with the packer assembly. The packer assembly consists of an upper and lower packer with two rubber casing cup elements on each packer, pointed opposite each other to contain pressure from above and below, and a casing sleeve that connects the upper and lower

packers. The casing sleeve is generally the largest size casing that will fit inside the old long string casing so as to allow a maximum by-pass area between the sleeve and the injection string. The length between the upper and lower concentric packer is determined by how many joints of casing is used for the sleeve. The length of casing sleeve required to isolate the leaks is dependent on the location of the bad sections in the long string. The overall length of a concentric packer assembly can range in length from 30 feet to several hundred feet depending upon the condition of the casing. The longest casing sleeve run to date on a concentric packer is 365 feet in a well that had several areas of bad casing within that interval.

There are two basic concentric packer configurations. The configuration seen in Figure 1 is not attached to the tubing in any way. This configuration is assembled around the tubing while being run in the hole. As can be seen in Figure 1, the tubing collar above the upper packer will push the assembly down the hole and the tubing collar below the lower element will pull it out when the tubing is removed. The second type of configuration is actually attached to the tubing string by use of a stinger assembly located on the lower packer.

In both configurations, the rubber casing cups on the packer fit against the old casing and are energized with pressure in the annulus to form a seal above and below the bad section of casing after the injection packer is mechanically set above the injection zone.

To maximize the concentric packers effectiveness in isolating a leak, the casing wall should be cleaned to facilitate the ability of the rubber casing cups to form a seal. Sharp or extremely rough areas of the casing should be dressed out to prevent tearing of the rubber elements while the packer is being run. In addition, the appropriate durometer rating for the rubber elements should be selected to compensate for any corrosion of the casing wall. Particular care should be given during the workover operation to accurately determining the location of all leaks and to placing the packer assembly over this interval.

Field results have demonstrated that if all of the above points are adequately addressed, the concentric packer will be effective in isolating the bad section of casing and allow the well to pass the mechanical integrity test unless other problems manifest themselves during the test.

ECONOMIC COMPARISON OF REMEDIAL ACTION OPTIONS

The six case histories detailed in Table 1 represent a comparison of the typical costs associated with squeezing, installing a liner, and running a concentric packer. A case history covering the cost of backing off old casing and

FIGURE 1

CONCENTRIC PACKER ASSEMBLY

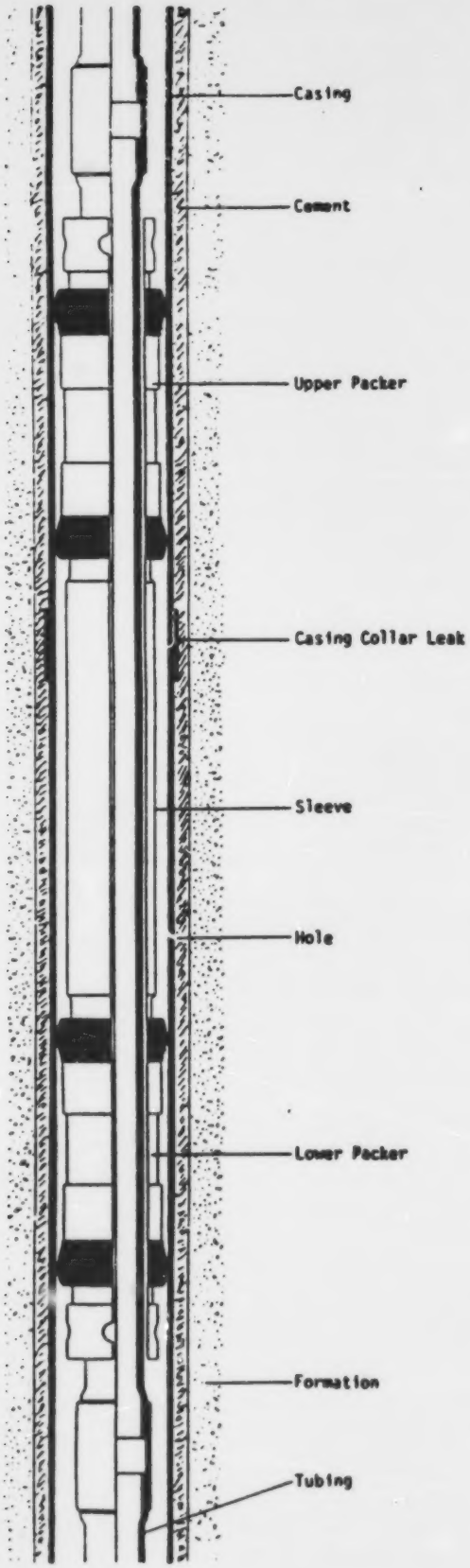


TABLE 1

CASE 1:	CONCENTRIC PACKER	
	7" X 5 1/2" X 2 7/8" CONCENTRIC PACKER	$ 1100
	WORKOVER RIG	720
	5 1/2" LINER (42')	230
	TRUCKING, SUPERVISION & LABOR	500
		$ 2550
CASE 2:	CONCENTRIC PACKER AFTER TWO SQUEEZE JOBS	
	WORKOVER RIG	$11000
	CEMENT & CEMENT SERVICES	3500
	TOOLS, TRUCKING, SUPERVISION & LABOR	7010
		$21510
	7" X 4 1/2" X 2 3/8" CONCENTRIC PACKER	$ 1100
	4 1/2" LINER (108')	600
	WORKOVER RIG	1000
	TOOLS, TRUCKING, SUPERVISION & LABOR	1400
		$ 4100
CASE 3:	TWO SQUEEZE JOBS	
	WORKOVER RIG	$15000
	CEMENT & CEMENT SERVICES	3200
	TOOLS, TRUCKING, SUPERVISION & LABOR	7100
		$25300
CASE 4:	5 1/2" LINER IN 7" CASING	
	WORKOVER RIG	$10000
	5 1/2" LINER (2500')	12500
	CEMENT & CEMENT SERVICES	2500
	5 1/2" X 2 3/8" INJECTION PACKER	1000
	TOOLS, TRUCKING, SUPERVISION & LABOR	8900
		$34900
CASE 5:	3 1/2" LINER IN 5 1/2" CASING	
	WORKOVER RIG	$10000
	3 1/2" LINER (2600')	8500
	2 1/16" TUBING	6400
	3 1/2" X 2 1/16" INJECTION PACKER	1800
	CEMENT & CEMENT SERVICES	2000
	TOOLS, TRUCKING, SUPERVISION & LABOR	9400
		$38100
CASE 6:	CONCENTRIC PACKER	
	4 1/2" X 3" X 2 3/8" CONCENTRIC PACKER	$ 650
	WORKOVER RIG	4100
	3" LINER (365')	1130
	2 3/8" TUBING W/ CROSSOVERS TO 2 7/8" TUBING	540
	TOOLS, TRUCKING, SUPERVISION & LABOR	2680
		$ 9100

replacing it with new is not included due to the fact that the operation is generally feasable only when the leak is at the very top of the casing string and the pipe is free of cement and debris.

The situation detailed in Case 2 is represented by the well schematic in Figure 2. This schematic illustrates the situation where a well has been squeezed several times in an attempt to repair the casing and pass the mechanical integrity test. Although the squeeze jobs successively reduced the magnitude of the leaks, they were unsuccessful from the standpoint of adequately repairing the leaks so that the casing could demonstrate integrity After the third squeeze, a concentric packer was utilized to isolate the entire interval of bad casing and allowed the well to pass the mechanical integrity test.

The actual workover operation and associated costs of a squeeze job performed on an injection well is summarized in Table 2 while Table 3 summarizes a hypothetical workover operation and the associated costs of running a concentric packer on the same type of well. Comparison of the two procedures indicates that had the option of using a concentric packer existed at the time the squeeze jobs were performed, a cost savings of approximately 63% could have been realized.

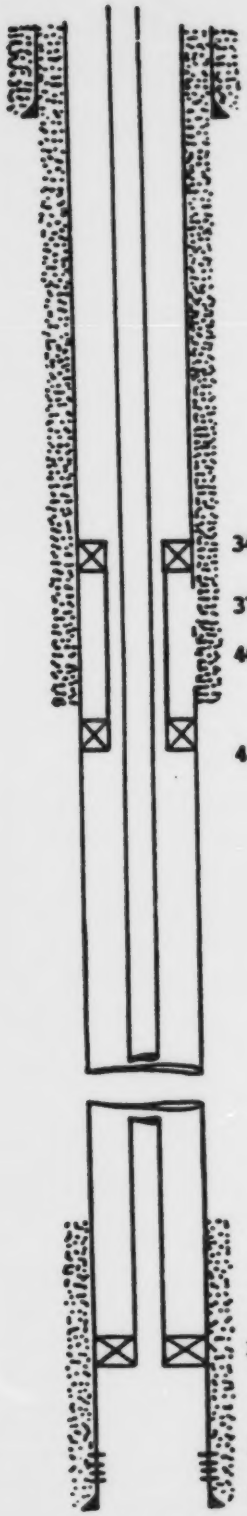
The workover operation and costs summarized in Table 4 are those associated with utilizing a concentric packer on a well with a casing leak that was determined inappropriate to squeeze based on its size and proximity to a highly permeable sandstone formation. Review of other wells previously squeezed in the same area indicated that the minimum expected cost of a squeeze job would be $5250 with at least two squeeze jobs needed to adequately correct the problem in order to demonstrate mechanical integrity. Using a concentric packer, the operator was able to locate the leak, repair the well, pass the mechanical integrity test and resume injection within one day which resulted in considerably less downtime and expenses than a squeeze job.

SUMMARY

Comparison of the procedures and associated well costs demonstrates that the use of a concentric packer is an attractive alternative to squeeze cementing or running a liner in a well for the purpose of acquiring mechanical intergity of the casing. Although savings are dependent upon the operating protocol of the oil company involved in the workover and the individual well conditions, the use of a concentric packer in an appropriate situation can result in a significant savings in repair costs and in time needed to get the well back in service.

FIGURE 2

COMPLETION SCHEMATIC FOR CASE 2



68' 10 3/4" CEMENTED W/ 60 sx

348' TOP OF 7" x 4 1/2" x 2 3/8" CONCENTRIC PACKER

373'-404' SMALL PINHOLE OR COLLAR LEAK SQUEEZED TWICE

404'-436' LARGE HOLE. CEMENT TO SURFACE AND SQUEEZE TO 500 PSI

465' BOTTOM OF CONCENTRIC PACKER

2785' 7" x 2 3/8" AD-1 TENSION PACKER

2905'-2966' PERFORATIONS

2974' 7" CEMENTED W/ 270 sx

TABLE 2

OPERATION SUMMARY OF CEMENT SQUEEZE AS PERFORMED ON INJECTION WELL

1. Move in rig up well service unit & blow well down
2. Trip out hole w/tubing & packer
3. Trip in hole w/retrievable bridge plug & packer on tubing
4. Set retrievable bridge plug at 2780'
5. Pressure test retrievable bridge plug
6. Isolate casing leaks at 2407'-2500'
7. Pump 1 1/2 BPM at 300 psi
8. Trip in hole & latch onto retrievable bridge plug
9. Attempt to set retrievable bridge plug at 2809',2780', and 2620'
10. Unable to shut off flow: Trip out hole w/tubing and tools
11. Trip in hole and set cast iron bridge plug by wireline at 2805'
12. Trip in hole w/open ended tubing to 2572'
13. Move in rig up cementers
14. Spot 100 sx cement from 2572' to 2034'
15. Trip out hole w/tubing and fill casing w/water
16. Pressure casing to 750 psi: squeeze 1 1/2 bbl cement behind pipe
17. Shut-in and wait on cement
18. Trip in hole w/bit and 2 drill collars on tubing: Top of cement at 1800'
19. Drill cement to 2580'
20. Pressure test casing to 200 psi. Held OK
21. Drill cast iron bridge plug at 2805'
22. Clean out well to TD of 2985'
23. Trip out hole and lay down tubing and tools
24. Trip in hole w/Baker AD-1 packer on tubing
25. Load annulus w/packer fluid
26. Set packer at 2791'
27. EPA mechanical integrity test to 200 psi. Held OK
28. Release pressure
29. Resume injection

COST SUMMARY

Well service unit	$ 4764
Tank truck service	687
Tools	1440
Wireline service	695
Baker AD-1 packer	1175
Cement and services	1497
	$10238

TABLE 3

HYPOTHETICAL OPERATION SUMMARY UTILIZING A CONCENTRIC PACKER TO REPAIR CASING ON INJECTION WELL

1. Move in rig up well service unit & blow well down
2. Trip out hole w/tubing & packer
3. Trip in hole w/retrievable bridge plug & packer on tubing
4. Set retrievable bridge plug at 2780'
5. Pressure test retrievable bridge plug
6. Isolate casing leaks at 2407'-2500'
7. Trip out hole w/retrievable bridge plug and packer on tubing
8. Trip in hole w/ Baker AD-1 and concentric packer with 103' of casing sleeve on tubing.
9. Load annulus w/packer fluid
10. Set Baker AD-1 packer at 2791'
11. EPA mechanical integrity test to 200 psi.
12. Release pressure
13. Resume injection

COST SUMMARY

Well service unit	$ 450
Tank truck service	200
Tools	300
Casing sleeve	530
Baker AD-1 packer	1175
Concentric packer	1100
	$ 3755

TABLE 4

OPERATION SUMMARY AS PERFORMED ON #1 SWD

1. Move in rig up well service unit and wireline unit
2. Run radioactive tracer survey: pinpoint leak at 165'-195'
3. Trip out hole with tubing and packer
4. Trip in hole with injection packer and concentric packer on tubing
5. Run tracer survey for EPA: no leaks
6. Rig down well service unit and wireline unit
7. Resume injection

COST SUMMARY

Well service unit	$ 375
Tracer survey	600
Casing sleeve (40')	160
Concentric packer	1100
	$ 2235

THEORY, DESIGN AND OPERATION OF AN ENVIRONMENTALLY MANAGED PIT SYSTEM

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Introduction

Onshore Drilling has traditionally utilized a single large reserve pit to contain drilling waste cuttings, water, and other liquids. Today, however, with increased environmental awareness and responsibility, land owner concerns and the complications of greater drilling depths, the traditional reserve pit can be extremely expensive if not prohibitive to operate.

This paper addresses an environmentally managed reserve pit system that can minimize the cost of the disposal of drilling wastes. This is accomplished by constructing a reserve pit system consisting of four or more pits and managing the wastes in these pits to segregate relatively uncontaminated wastes from the more contaminated wastes. The program maximizes the use of the traditional onsite disposal methods, land farming, burial, and injection, while minimizing or eliminating offsite disposal.

The most effective application of this system is when drilling waste can be land farmed and/or injected onsite, though experience has shown that the use of the system can result in savings when much of the waste is handled offsite.

The use of this system depends on the proper planning and communication coupled with proper location design and effective pit management.

System Design

A successful environmentally managed reserve pit program must begin with a design meeting. This should include representatives of the operator, (such as drilling engineers, operations, land, and environmental personnel), site preparation contractors and reserve pit management personnel. Items of discussion should include the well drilling program, orientation

of the location and positioning of the well stake, available acreage adjacent to site for land farming, landowner concerns and regulatory limitations, choice of drilling contractor and rig, and accessibility to the drill site.

The next step in the design program is site assessment. This should include photographs of the site, preliminary background soil sampling and testing, establishing good communications with the landowner, and determine the possibility of flooding conditions, runoff areas and other land conditions.

1. Background testing of the soil is highly recommended to determine the possibility of pre-existing contaminants in the soil and to establish soil characteristics that may affect land farming operations.

2. Good communications with the landowner can answer many questions about how the area handles rain water runoff and land use prior to and after drilling.

A management checklist, as shown in Fig. 1, is used to assemble the data to be used in the reserve pit design, as shown in Figure #1. Based on the information gathered, the reserve pit system is then designed to handle the volumes of waste to be generated, the expected weather conditions, the planned disposal of the drilling generated waste, and oriented to the planned drill site.

The environmentally managed reserve pit system is predicated on two primary operation considerations:

1. Ability to land farm non-contaminated material on site.

2. Annular disposal of contaminated material down hole.

The use of annular disposal requires approval from the appropriate regulatory agency and is affected by casing depths, cement requirements and underground sources of drinking water (USDW).

Land farming operations for a reserve pit management project requires an additional four to five acres of land in addition to the actual drill and pit site. This is necessary as the solids should be spread to a maximum of three inches in thickness. Amounts in excess of three inches will not de-water and dry properly, making land farming and dilution difficult.

From the above parameters, a pit system is designed. A typical pit system design is shown in Fig. 2. The design shown in Fig. 2 should not be considered as a fixed design as it represents only what was required for one particular well. Flexibility in this pit system allows for different configurations, orientation, number, and size of pits to accommodate most locations, well depths, and drilling mud programs.

Construction

The construction of the environmentally managed reserve pit system should be performed by a reputable site preparation contractor who is familiar with the application of the system, utilizing proper equipment, and under competent supervision. This should assure the operator of receiving a finished product that meets specifications and site plans.

The levee walls are constructed in a manner to allow movement of heavy equipment such as draglines on the levees to work each of the pits. The entire reserve pit system is constructed in an area that normally would hold a traditional 200' x 300' reserve pit for a well to be drilled 14,000' to 18,000'.

Typical equipment used on managed reserve pit locations include draglines, bulldozers, and pile driving equipment (if a bulkhead is constructed).

One option the operator has during the construction phase is to include a timber bulkhead in lieu of an earthen levee on the rig side of the shaker pit (Detail A, Fig. 2). The purpose of the bulkhead is to reduce the length of slides and pipes leading from solids control equipment to the pit and to increase the drop angle of the slides and pipes. This reduces the tendency of the slides and pipes to clog during the drilling operation which requires flushing with water. This in turn reduces water volume in the pit which ultimately requires some method of disposal. Although the bulkhead system increases the up-front construction costs, it will save costs on the volume of water to be handled during drilling.

Reserve Pit Operation

In daily operation of the environmentally managed reserve pit system, Pit #1 is "The Shaker Pit". The waste generated by the solids control equipment is discharged into this pit. Material in this pit may be moved by dragline to Pit #2 for storage or moved directly to the land farming area. Fluid may be transferred from Pit #1 to Pit #3 through a PVC pipe set in the levee wall or with centrifugal pumps. This fluid in Pit #3 is stored

to allow the solids to settle. The water is then moved by centrifugal pumps to Pit #4. The water in Pit #4 is either recycled for rig use or tested and treated for discharge as allowed by regulations. Rain water and waste water from the location may be pumped directly to Pit #3. Pit #5 is provided to contain salt water flows, cement over runs, and other emergency pit functions.

Maintenance of freeboard or maximum allowed volume in the pit system by treating and discharging water can be a costly item depending on the duration of the drilling operations. Water conservation items to be considered for use on a proposed drilling program include:

1. Construction of drillsite location no larger than necessary.

2. Use of automatic shutoff nozzles on all hoses on rig floor and washdown racks.

3. Recycling of reserve pit water to wash out slides draining to shaker pits.

4. Use of ring levee water (if acceptable) for makeup water.

5. Use of drip pan beneath rig floor with flexible hoses draining to cellar to avoid dirty water and mud dripping on rig substructure and location area.

6. Installation of water meters on fresh water sources to monitor and control water usage.

Reserve Pit Monitoring

An environmentally managed reserve pit program requires daily monitoring of the project by the reserve pit management personnel. The status of the pit system is surveyed daily to determine volumes in each pit, changes from the previous day, work performed in handling wastes from any of the pits, rainfall amounts, and weather conditions. This information is charted daily on the work progress report (Fig. 3) and provides documentation on waste volumes handled throughout the job and disposal methods utilized.

Samples can be extracted from the pit system and analyzed or bench tested by an approved laboratory in accordance with current State rules and regulations. The analyses of these samples dictate the disposal method used.

Open communication between the reserve pit management personnel, mud company personnel, drilling contractor and the company representatives is very important. All parties involved must know complete daily activity and also what is planned for the following day. A successful reserve pit management program requires the cooperation of all parties mentioned above which is usually stressed at the "spud meeting" before drilling actually begins.

Waste Management

A reserve pit management is based on handling drilling waste by onsite disposal methods. The program uses traditional onsite disposal techniques including land farming mud and cuttings which meet regulatory guidelines for onsite disposal, burial, treating and discharging of pit water and rain water, and injection. In the event that one or all of the onsite disposal methods cannot be used, offsite disposal of the contaminated material at an approved commercial disposal facility may be necessary. This is the last option considered due to increased costs when compared to onsite methods.

Land farming operations consist of isolating mud and cuttings and spreading this material no greater than three inches thick, allowing the material to de-water, then plowing the solids into the existing ground to the appropriate depth to achieve proper dilution. The application of soil amenities and replowing is acceptable.

Treating and discharging of pit water occurs when enough water has been generated to fill the treating pit. Pit water samples are extracted and analyzed in accordance with current rules and regulations to determine the level of contamination, chemically treated to reduce contaminants to within regulatory limits, then re-analyzed, and finally discharged onsite after obtaining regulatory approval.

Pit waste that cannot be land farmed or chemically treated and discharged is stored in the reserve pit system for annular disposal. The pit waste is physically mixed into a slurry by using a dragline, then fed to a disposal pump unit which screens out the larger solids, and injects the material. Chart recording equipment is used to monitor pumping pressures, record pumping time and disposal volumes.

Any residue remaining in the pit system after annular injection that cannot be dealt with onsite requires offsite disposal. This process consists of loading the material into vacuum trucks if it is wet, or into dump trucks if it is drier, and then hauled by an approved commercial disposal

facility.

Final Reserve Pit Clean Up

Once drilling operations are complete and all of the options described above have been implemented, the reserve pit management system can be backfilled using earthen levee material. Any trash and debris is removed from the site and properly disposed. The pit system area is leveled and restored to predrilling conditions. Post closure sampling and analyses are performed on the backfilled area to insure compliance with current rules and regulations. All documentation is compiled into a post closure package for the operator's files and is helpful in filling out forms concerning the disposition of the waste.

Advantages of a Managed Reserve Pit System

The two main advantages of the managed reserve pit system are the ability to process drilling wastes as generated and the isolation of wastes to minimize contamination. These advantages are reflected in lower disposal costs.

The ability to process drilling waste as generated is significant in that it reduces the volume available for contamination, it reduces the impact of unexpected problems, and it keys rig personnel to the effects of their actions on waste management. By processing the waste as generated, only a small volume of waste is present in the pit system which could potentially be contaminated. In a conventional reserve pit, the entire pit contents could be contaminated.

The ability to isolate waste is beneficial because it prevents small amounts of highly contaminated waste from impacting large amounts of manageable waste. It also allows flexibility in the scheduling of waste processing. In addition, isolation provides the opportunity for selected waste to be treated by alternative methods such as solidification, dewatering, etc.

Conclusion

An effectively designed and environmentally managed reserve pit system can not only facilitate compliance with the regulations on reserve pit closure and disposal of drilling waste; it can reduce the cost of compliance. The proper design, construction, and daily management of a managed reserve pit

system can minimize or eliminate the volumes of drilling waste that require offsite disposal. The result can be substantial savings over conventional methods currently available.

FIGURE 1

RESERVE PIT CONSTRUCTION, MONITORING, & MANAGEMENT CHECKLIST

Operator/Drilling Co. _____ DATE:_____

Well Name _____

Location of Well _____

Company Man _____ Ph. # _____

Well Depth _____ Ft. No. of Days _____

Mud Program _____ Casing Program _____

_____ _____

_____ _____

_____ _____

_____ _____

_____ _____

Land Available _____ Acres

Site Map Available Yes ___ No ___

Rig Plat Available Yes ___ No ___

Pumping of Water During Drilling Yes ___ No ___

Pumping of Mud & Water After Drilling Yes ___ No ___

Pumping Rate Allowed _____ bbl/min

Max. Pumping Pressure _____ PSI

Will Background Testing Be Done Yes ___ No ___

Bid Due Date _____

Additional Comments:

_____

_____

_____

_____

_____

FIGURE 2

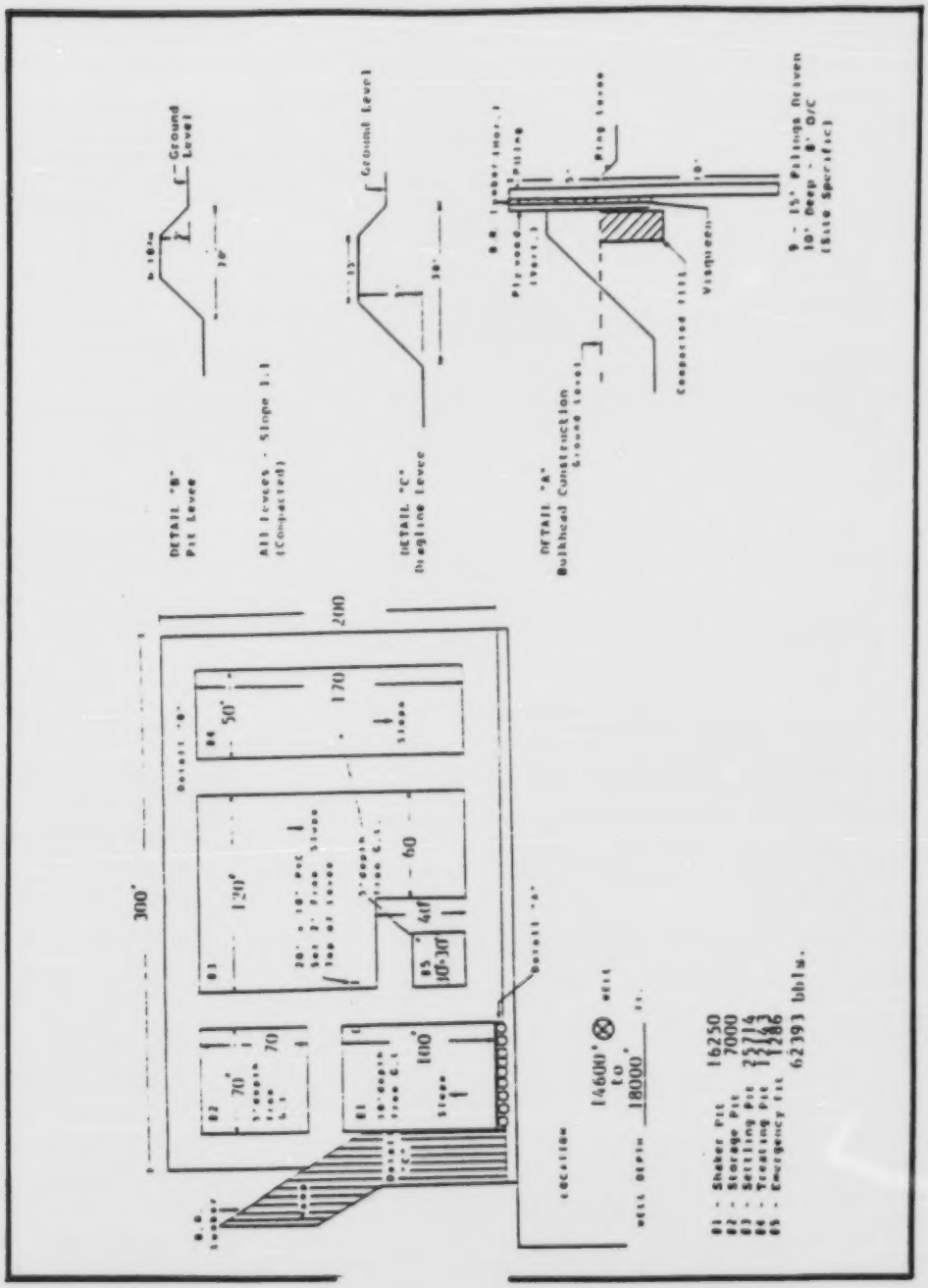
DETAIL "B"
Pit Level
Ground Level
All Levees - Slope 1:1
(Compacted)
DETAIL "C"
Dragline Levee
Ground Level
DETAIL "A"
Bulkhead Construction
Ring Levee
Visqueen
9 - 15' Pilings Driven
10' Deep - 8' O/C
(Site Specific)
300'
200'
170'
120'
50'
70'
60'
110'
40'
30'
14600' to 18000'
62391 bbls.

FIGURE 3

DAILY PROGRESS REPORT

WASTE MANAGEMENT/TURNKEY REPORT

FOREMAN _____ REPORT NO. _____

DATE: _____

OPERATOR: _____

WELL NAME _____

LOCATION: _____

Pit #	Type	Depth Feet	Vol. Per Feet	Total Vol.	Change From Previous Day (+ or -)
____	____	____	____	____	_____
____	____	____	____	____	_____
____	____	____	____	____	_____
____	____	____	____	____	_____
____	____	____	____	____	_____
____	____	____	____	____	_____

Rain Gauge: AVG. _____ IN. Weather: _____

COMMENTS:

DEPTH _____

MUD WT _____

AFTER TREATING WATER

CERTIFIED LAB ANALYSIS PERFORMED BY (LAB) _____ DATE _____

PHONE _____

LAB RESULTS:

____ pH

____ (TSS) TOTAL SUSPENDED SOLIDS

____ CHLORIDES (PPM)

____ OIL & GREASE

____ (COD) CHEMICAL OXYGEN DEMAND

____ CHROMIUM

____ ZINC

DEQ APPROVAL BY _____ DATE _____ TIME _____

VERBAL OR ONSITE

TOXICITY AND RADIUM 226 IN PRODUCED WATER —— WYOMING'S REGULATORY APPROACH

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Introduction

In 1989 the State of Wyoming produced about 108 million barrels of oil and about 861 million Mcf of natural gas. These levels of production placed the state sixth in the nation for both oil and natural gas production (1).

Associated with the production of this oil and natural gas was approximately 1.65 billion barrels of produced water. About 70% of this produced water was reinjected or pumped into disposal wells and about 30% (495 million barrels) was discharged into surface streams and drainages (1). The discharges to the surface are regulated by the Wyoming Department of Environmental Quality (DEQ) through the National Pollutant Discharge Elimination System (NPDES) discharge permit program. It is these discharges which are the subject of this paper.

There are currently 610 active produced water NPDES permits in the state. About 95% of these permits are associated with wells producing oil only or oil and natural gas. Only about 5% are associated with wells producing only natural gas or coal bed methane.

Regulatory History

The NPDES program can be delegated by the U.S. Environmental Protection Agency (EPA) to the states. Wyoming has had primacy for the NPDES program since 1974.

In 1976 when the EPA proposed effluent standards for produced water, it identified best practicable treatment (BPT) for on-shore oil and gas production as "no discharge of produced water". EPA's position was that reinjection was an efficient and cost effective alternative to surface discharge.

Adoption of the proposed EPA regulation would have meant the elimination of all produced water discharges in Wyoming. Because Wyoming is a semi-arid state and because much of the produced water in the state is relatively "fresh" (less than 5,000 mg/l of total dissolved solids), loss of the produced water would have meant the loss of important sources of water for stock and wildlife. Because of this, the state expressed strong objection to the EPA proposal.

As a result of the state's efforts and with the assistance of EPA Region VIII, the final version of the EPA regulation contained an "Agriculture and Wildlife" subpart. This section of the regulation allows the surface discharge of produced water provided the following conditions are met:

1. That the discharge is located west of the 98th meridian;

2. That the produced water is of good enough quality to be used for wildlife and livestock watering or other agricultural uses and that the produced water is actually put to such use during periods of discharge; and

3. That the oil and grease concentration not exceed 35 mg/l.

While the state was generally satisfied with the final form of the federal regulation, it still had two concerns. First, the allowable oil and grease concentration of 35 mg/l was much higher than was acceptable. The state had data from its own sampling as well as the sampling of the dischargers which showed that a properly operated and maintained system consisting of a heater treater followed by a series of skim ponds could consistently meet an oil and grease limitation of 10 mg/l. Second, the state felt that proving that a discharge was actually being put to use for agricultural and wildlife purposes was going to be a cumbersome and time consuming process. In addition, the regulation seemed to prohibit new produced water discharges since it would be impossible to show that the discharge was being put to use if it had not yet occurred.

The solution to this problem was for the state to adopt its own produced water effluent regulations within the general framework of the federal regulation. Therefore, in 1978 Wyoming adopted the produced water effluent standards (2) summarized in Table 1.

TABLE 1

Summary of State of Wyoming produced water effluent standards

Parameter	Standard
Chlorides	2,000 mg/l
Sulfates	3,000 mg/l
Total Dissolved Solids	5,000 mg/l
Oil and Grease	10 mg/l
pH	6.5 - 8.5 std. units
Toxic Substances	None in concentrations or combinations that are toxic to human, animal, or aquatic life

Because the state's oil and grease standard was more restrictive than the federal standard, EPA had no objection to that part of the state regulation. In addition, the state took the position that any discharge meeting the limitations shown in Table 1 was suitable for stock and wildlife use, and assumed that the water was actually being put to such use. EPA's Region VIII, which has oversight authority for Wyoming's NPDES program, has accepted this approach.

Toxicity

While the state has had language in its regulations since 1977 prohibiting the discharge of toxic substances (see Table 1), no serious effort was made to identify or quantify the presence of toxics in produced waters in Wyoming until 1987. There were two reasons for this: first, most (about 85%) of these discharges flow into intermittent or ephemeral drainages which are not protected for aquatic life uses. In addition, the waters were clearly being used for stock and wildlife watering with no apparent ill effects. Second, for those discharges which do flow into live waters, there did not appear to be any obvious problems (no reports of fish kills or complaints from the wildlife management agencies). However, it must also be stated that there was a limited amount of information in the state's files as well as in the literature (8) to indicate that the presence of aquatic life toxicants in produced water was a distinct possibility.

In 1987, EPA's Region VIII began to aggressively promote the use of "whole effluent toxicity" (WET) testing as an economical and efficient means of determining the toxicity of wastewater discharges. The WET test involves exposing aquatic organisms (usually an invertebrate such as Ceriodaphnia dubia and a fish species such as fathead minnows) to varying concentrations of wastewater effluent. The reaction of the organisms (mortality, loss of weight, or reduction in reproduction) is used to estimate the relative toxicity of the effluent to aquatic life in general.

In August of 1987 the state sent effluents from eight different Wyoming produced waters to EPA for preliminary screening. EPA's testing revealed varying levels of acute toxicity (mortality) to Ceriodaphnia in seven of the eight effluents. In October of 1987, EPA sent their mobile laboratory from Duluth, Minnesota to Casper, Wyoming to run acute and chronic WET tests on produced water effluents. The results of EPA's testing (3) are summarized in Table 2.

In addition to conducting the WET tests, EPA also conducted Toxicity Identification Evaluations (TIEs) on eight different Wyoming produced waters. Those investigations indicated that in most cases hydrogen sulfide (H_2S) was the suspected primary toxicant but that, in at least one case, a non-polar organic was probably the primary toxicant. In the particular effluents tested, salinity did not appear to cause toxicity even though total dissolved solids (TDS) concentrations were in the 2,000 - 4,000 mg/l range. It was concluded that salinity toxicity would be more likely if more of the salinity would have been in the form of sodium chloride.

This EPA study provided conclusive evidence to the state that produced water discharges had significant potential for toxicity and that, at least for those discharges flowing into class 1, 2, or 3 waters (waters which receive aquatic life protection under Wyoming's standards), corrective actions would be necessary. Also at this time, EPA directed the states to begin preparation of their 304(l) lists. Section 304(l) of the federal Clean Water Act requires each state to identify its toxic discharges and to develop a strategy for eliminating the toxicity by July, 1992. In response the state began an exhaustive field review of all of its produced water discharges. The purpose of the field review was to place each discharge into one of the following three categories:

Category 1 - Discharge flows immediately into a class 1, 2, or 3 water.

Category 2 - Discharge flows into a class 1, 2, or 3 water after traveling a significant distance in a class 4 water.

Category 3 - Discharge will not reach a class 1, 2, or 3 water under dry weather conditions.

TABLE 2
Acute and chronic toxicity in four produced waters in Wyoming

Organism/Test	Timberline	Conoco 03	Conoco 90	Amoco LACT 11
Ceriodaphia/LC50(1)	55%	2%	55%	5%
Fathead M./LC50	55%	2.6%	31%	2.5%
Ceriodaphia/LOEC(2)	10%	1%	30%	3%
Fathead M./LOEC	30%	3%	-	3%

(1) The 50% lethal concentration or the effluent concentration at which 50% mortality to the test population occurs. Ceriodaphnia exposed for 48 hours, fathead minnows for 96 hours.

(2) The lowest observed effect concentration or the lowest effluent concentration at which a statistically significant reduction in reproduction (Ceriodaphnia) or growth (fathead minnows) occurs.

(Summarized with permission from Taraldsen, Amato, and Mount, Toxicity Testing and Characterization of Toxicants From Effluents of the Powder River Basin, Wyoming.)

The state's field review resulted in the placement of 50 discharges into category 1, 57 discharges into category 2, and 503 discharges into category 3. Those facilities in category 1 were then placed on the state's 304(1) list and the NPDES permit for each was modified to include the following:

1. A requirement to conduct two species (Ceriodaphnia and fathead minnow) acute toxicity tests on at least an annual basis;
2. A requirement to eliminate toxicity by July 1, 1992; and
3. A list of three options for achieving compliance, including:
   a. Treatment to remove acute toxicity;
   b. Elimination of the discharge; or
   c. Passing the two species chronic toxicity tests by utilizing the dilution factor in the receiving stream.

The status of the category 1 discharges as of July 1, 1990 is given in Table 3.

Table 3
Compliance Status (as of July 1, 1990) for category 1 discharges

Out of compliance due to failing acute toxicity test for both species	15
Out of compliance due to failing acute toxicity test for Ceriodaphnia only	3
Out of compliance due to failing acute toxicity test for fathead minnows only	2
Out of compliance due to failure to test	3
In compliance due to passing acute test for both species	3
In compliance through elimination of the discharge	6
In compliance due to passing of the chronic toxicity test for both species	2
In compliance due to an expected reduction in stream classification	3
Not tested, but facility typically non-discharging	12

Information from the dischargers indicates that, in many cases, acute toxicity can be removed through aeration and that the most common toxicant encountered is hydrogen sulfide. However, many operators are indicating that their preferred method of achieving compliance is through reinjection. Reinjection has the following advantages over treat and discharge:

1. The solution is final in the sense that there is no concern about future changes in toxicity requirements;

2. Since there is no discharge there is no possibility of being out of compliance;

3. The testing and reporting costs associated with monitoring an NPDES discharge are eliminated;

4. The costs of operating and maintaining a treatment system are eliminated, although they may be replaced or outweighed by the costs of reinjection;

5. In some cases the produced water can be used to enhance oil production by increasing pressures in the producing formation.

Action on the category 2 discharges is not expected to be initiated until after 1992 when compliance by the category 1 dischargers should be complete. Considerable work still has to be done to determine to what extent toxicity is reduced or eliminated when produced waters travel long distances in open channels prior to confluence with flowing streams. Preliminary evidence indicates that toxicants which tend to be volatile in nature are effectively removed by natural aeration processes. More persistent toxicants, such as chlorides, appear to be uneffected. This conclusion is supported by the work of Lamming (4) who observed chronic toxicity effects on Ceriodaphnia 68 kilometers below a number of large volume produced water discharges. However, it is the position of the state that WET test results should be supplemented with in-stream bioassays. King (5) studied zooplankton populations in Wyoming stock ponds and observed little difference between those consisting primarily of produced water versus those consisting only of natural runoff.

At this time the state has no intent of addressing toxicants in the category 3 discharges. Such discharges do not effect waters protected for aquatic life uses; however, such discharges are used extensively by stock and terrestrial wildlife. There is no evidence to date that stock and wildlife are adversely effected by drinking produced water, although research in this area is very limited.

Radium 226

In early 1989, the State of Wyoming received a report (6) from the State of Louisiana's Department of Environmental Quality which addressed the problem of radiation associated with oil and gas production. Information in that report indicated that produced waters had the potential to be high in dissolved radium 226. In response, the Wyoming DEQ selected four of its produced waters at random and had them analyzed for radium 226. Three of the four samples showed total radium 226 levels of 0-10 picoCuries/l (pCi/l). Levels such as these are not considered to be unusual; however, the fourth sample showed a radium 226 concentration of approximately 1,200 pCi/l. Subsequent sampling of this discharge and analysis by a second laboratory resulted in a reading of about 1,700 pCi/l.

This single very high value indicated to the state that there was at least the potential for a problem with high radium 226 levels in Wyoming produced waters. Therefore, in August of 1989 the agency requested that all produced water dischargers test for radium 226 and submit the results to the DEQ within six months. Results of this voluntary self-monitoring program are given in Table 4.

Currently Wyoming has an in-stream standard for radium 226 plus radium 228 of 5.0 pCi/l. This standard is based on the national drinking water standard but applies to all waters in the state regardless of whether or not the water is classified for drinking water use. Since produced water discharges often comprise the only flow in intermittent streams, discharges to such streams were faced with the prospect of having to meet a 5.0 pCi/l radium limit at the point of discharge.

This situation caused DEQ to reevaluate the appropriateness of using the federal drinking water standard for waters not used for human consumption. Investigation of the matter revealed that the Nuclear Regulatory Commission (NRC) had established a limitation on radium 226 for unrestricted access waters (waters not being used for human consumption) of 30 pCi/l. Further investigation showed that the NRC is currently in the process of reviewing that regulation and that the new proposal is for a 60 pCi/l limit (7). Since the NRC's unrestricted access waters appeared to be analogous to waters classified by the State of Wyoming as class 3 and 4 waters, DEQ has proposed changing its in-stream standards for class 3 and 4 waters from 5 pCi/l of radium 226 plus 228 to 60 pCi/l of radium 226. The state plans to leave its standard for class 1 and 2 waters, which are classified for drinking water use, at 5 pCi/l of radium 226 plus 228.

TABLE 4

Total radium 226 concentrations in Wyoming produced waters

Total number of discharges tested	373
Highest recorded value	2,152 pCi/l
Lowest recorded value	0 pCi/l
Average value	21.5 pCi/l
Median value	3.7 pCi/l
Number of values greater than 1,000 pCi/l	2
Number of values greater than 100 pCi/l	6
Number of values greater than 60* pCi/l	15
Number of values greater than 5** pCi/l	167
Number of values less than 5 pCi/l	206

* Proposed Nuclear Regulatory Commission Standard for unrestricted access waters

** U.S. EPA drinking water standard (radium 226 plus radium 228).

If the DEQ's proposed modification is accepted by the state's Environmental Quality Council, it is expected that approximately 50 produced water discharges will be effected. Since it is doubtful that radium 226 removal technologies will be practicable for produced waters, it is assumed that these discharges will be reinjected.

Summary

Wyoming has regulated produced water discharges to surface drainages since 1974. Until the late 1980's, the major pollutants of concern were salinity and oil and grease. In 1987, evidence was collected which showed that produced water effluents were likely to be toxic to aquatic life. It appears that produced waters often contain relatively short-lived volatile toxics that cause immediate acute toxicity and more persistent long-lived toxics that cause chronic toxicity effects. These toxicants are now being regulated in instances where discharges effect receiving waters protected for aquatic life uses. At this time there is no evidence that the consumption of produced water adversely effects stock or terrestrial wildlife, though research in this area is very limited.

Radium 226 concentrations in Wyoming produced waters are highly variable ranging from over 2,000 pCi/l to 0 pCi/l. Where human drinking waters are a protected use, the federal drinking water standard is the appropriate in-stream standard. For waters which do not require human drinking water use protection, the proposed Nuclear Regulatory Commission Standard for unrestricted access waters of 60 pCi/l of radium 226 appears to be adequate.

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UNSUCCESSFUL OILFIELD WASTE DISPOSAL TECHNIQUES IN VERMILION PARISH, LOUISIANA

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Introduction

Vermilion Parish (county), Louisiana borders the Gulf of Mexico, in southwest Louisiana. Within the geographic boundaries of the parish, approximately 3,500 oil and gas wells have been drilled. These 3,500 wells are distributed throughout the parish in 66 oil and gas fields. The earliest recorded well was dug in 1922.

The waste from the oil and gas drilling and production activities within Vermilion Parish was disposed of on site as well as in a number of commercial facilities spread throughout the parish. Waste from adjacent parishes as well as other states was also disposed of in the commercial facilities located in Vermilion Parish. Today, only one commercial facility continues to receive oilfield waste. The other facilities stopped receiving waste in the mid 1980's. The closed sites have still not been cleaned up, and they all contain large quantities of waste. The environmental damage at three of the waste sites is so severe that the Environmental Protection Agency has designated the sites as Superfund sites.

Waste Disposal Methods/Problems

The off-site waste disposal of oil and gas drilling and production waste in Vermilion Parish has been accomplished by a wide spectrum of methods. The facilities utilized methods such as injection wells, unlined surface impoundments, land application, landfill, burial in excavated holes, and marsh reclamation utilizing untreated waste.

The environmental damage resulting from the disposal of the waste consist of extensive groundwater contamination, surface water contamination, marsh destruction, agricultural field damage, terrestrial environmental contamination, and aquatic and terrestrial biota contamination. The environmental damage is continuing today because the sources of contamination, the oil and gas drilling and production wastes are still present at each of the off-site commercial locations. The total impact of the environmental damage at each site is unknown due to lack of data. The three sites with the greatest amount of data are the three which are now Superfund sites. These sites are known as PAB Oil and Chemical Service, Inc. Gulf Coast Vacuum Services, and D. L. Mud, Inc.

PAB Oil and Chemical Services, Inc.

The PAB Oil and Chemical Services, Inc. site is a 9.4 acre oilfield waste disposal facility located north of the town of Abbeville. The site was approved by the Office of Conservation (Louisiana Regulatory Authority for oilfield waste) for the acceptance of oilfield waste. The site accepted waste from early 1976 until 1982.

The site contains five acres of waste lagoons consisting of four pits. Three of the pits are interconnected and contain oily sludge containing barium, chromium, lead, toluene, and other organics.

As early as April 1979 the pits were documented as having poor levee construction which was allowing waste to leach through. The site was judged a health hazard in 1979 due to its location one-quarter mile from a sand and gravel pit. In 1980, EPA documented 22 drinking water wells within one-quarter mile of the PAB site.

The EPA site assessment investigation identified the presence of contaminant plumes resulting from the migration of materials from the pits on both the surface and subsurface. Groundwater monitoring wells indicate elevated levels of barium, chromium, and nickel. There exist only five feet of clay, of unknown quality, between the bottom of the disposal pits and the top of the major local groundwater aquifer. Therefore, at the present time there exists the potential for major contamination of the groundwater aquifer.

There also exists the potential in the future for contamination of the municipal water wells serving the City of Abbeville. The EPA has determined that the PAB site directly affects 18,000 people and 2,100 people use the groundwater for irrigation.

Gulf Coast Vacuum Service

The Gulf Coast Vacuum Service site is a 12.78 acre site located southwest of Abbeville. The facility operated as a waste oil handling facility and truck washout facility. The site was operated in conjunction with a waste injection well located approximately two miles away.

Three open pits on the site were used to dispose of oil-based mud, drilling fluids, saltwater, and truck wash-out water. The pit contents and surface soils are contaminated with significant concentrations of arsenic, barium, cadmium, chromium, copper, lead, mercury, zinc, pentachlorophenol, naphthalene, benzene, and toluene. The pits contain liquids and sludges. The ground on the site has been built up with the contaminated pit sludges. The large pit is overtopping the levee each time it rains. The contaminants are flowing into an adjacent drainage and have contaminated the pasture area adjacent to the site. Cattle still graze in the contaminated pasture even though in 1988 the EPA recommended the contaminated pasture be restricted and secured.

In addition to the surface contamination, contaminants have migrated out of the pit and into the groundwater under the site. The shallow aquifer under the site is used for drinking water and irrigation of cattle, rice, and crawfish ponds. The EPA has determined that the Gulfco site directly affects 2,600 people.

D. L. Mud, Inc.

The D. L. Mud., Inc. site is a 12-acre site that was part of the original 25 acre Gulfco site. In 1981, 12.78 acres of the original site was sold to Dow Chemical. The site operated under the names of the Dow Chemical, Dowell Schlumberger, Inc., and D. L. Mud, Inc.

The facility was a drilling mud mixing facility when owned by Dow and D. L. Mud, Inc. Tanks on the facility were filled with drilling muds, saltwater, and drilling fluids. Waste sludges from the Gulfco pits were deposited on the ground as fill material. The soil and subsurface soils and sediments on the site are contaminated with significant concentrations of arsenic, barium, chromium, lead, mercury, zinc, and organic solvents. Organic and inorganic contamination has been detected down to a depth of 35 feet.

The waste remaining in the 15 tanks which range in size from 210 barrels up to 3,000 barrels was removed and disposed of in the Dow Hazardous Waste Incinerator in Plaquemine, Louisiana. The cleanup of the contaminated sludges and soils and groundwater have not yet been addressed.

The EPA has determined that the D. L. Mud site directly affects 2,600 people.

Status of Superfund Process

In August 1989, the EPA sent out notices to companies listed as potentially responsible parties (PRPs) for each of the three sites. The PAB site PRPs consisted of companies that disposed of oilfield waste in the PAB pits. The Gulfco and D. L. Mud sites' PRPs consist of companies that sent waste to the site as well as companies who had material transported by the truck service which disposed of the residual chemicals and truck wash water at the facilities.

The PAB site PRPs consisted of 166 companies. Ninety-one percent (91%) of the PRPs were Louisiana companies and 11 companies were located in Vermilion Parish. The D. L. Mud PRPs were composed of 306 companies. Fifty-six (56%) of the PRPs were Louisiana companies and four companies were Vermilion Parish companies. The Gulfco site had 442 PRPs of which 69% were Louisiana companies and nine were Vermilion Parish companies.

At the present time the EPA is planning to conduct remedial investigations at each of the three sites. These investigations are designed to assess the extent of the contamination at each site. The next step will be the feasibility study which will evaluate various remedial actions and clean-up methods.

Future of Waste Sites in Vermilion

The potential for additional Superfund sites in Vermilion Parish are being investigated as a part of the three present Superfund sites. A number of sites with known environmental problems received the same waste as that received by the three Superfund sites. These six sites, which are known as Superfund daughter sites, consist of the Pershing Broussard/Leleux Disposal site, the Leo Fontenot pit, the Seventh Ward dump, the Tan Romero/Sixth Ward dump, the Mar-Low/Oil Field Brine disposal site, and the John Nunez injection well.

In addition to the six daughter sites, EPA is currently investigating three other sites for inclusion on the Superfund list. These sites are known as the Forked Island Ship Yard location I and II and the Larry Landry Intracoastal city dump.

Oil and gas drilling and production waste was disposed of in seven other commercial facilities in Vermilion Parish. These seven sites in addition to the ones previously listed, all have environmental impacts as the result of the disposal of oilfield waste. The case study of unsuccessful oilfield waste disposal techniques in Vermilion Parish will continue to unfold for many years in the future. A complete understanding of the extent of the problem is presently hampered by a lack of financial resources. This lack of financial resources, likewise extends into the area of site remediation. Thus, site remediation at all sites within the parish is a dream which extends far into the future.

THE USE OF HYDROCYCLONES IN THE TREATMENT OF OIL CONTAMINATED WATER SYSTEMS

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Introduction

Water contaminated with oil is a large scale by-product of the production, transportation and refining of crude oil as well as a wide range of industrial processes. Increasing public awareness of the impact of oil pollution, together with tightening legal restrictions on environmental discharges (1) and a growing interest in recovering the oil product from the waste water and process equipment miniaturisation, have stimulated the development of innovative water/oil separator technologies where conventional systems have proved inadequate. One such development has been the emergence of effective liquid-liquid hydrocyclone separators, in particular for the treatment of oily water, after extensive research at the University of Southampton in the 1970's and early 1980's (2,3,4,5).

The hydrocyclone is an enhanced gravity separator which generates acceleration fields between several hundred and several thousand "g" by directing a pressurised feed flow tangentially into a generally conical vessel to create a confined vortex. Any dispersed component within the flow will segregate radially within the vortex by virtue of its density difference from the continuous component. Heavier material moves to the wall where it is carried away from the inlet to emerge at the apex of the unit whilst the lighter material migrates to the centre and is usually carried away from the apex by a reverse flow and out of a central aperture adjacent to the inlet.

Conventionally hydrocyclones have been used largely in mineral processing for the separation of solid fractions from a water phase. The classical geometry is a simple tangential feed pipe leading into a short cylindrical section on top of a steeply tapered cone, with inlet and outlet aperture sizes controlling the operation.

Figure 1 shows a schematic of a commercial (water) deoiling geometry based on the University research, illustrating how dealing with light oil drops rather than dense solids affects the design concept. Firstly, oil drops will be moving to the centre of the hydrocyclone to be separated, rather than the wall, and this means flow near the core must be kept free of instabilities or excessive turbulence which might allow re-mixing. In addition, the much lower density differences for oil/water systems implies the need for longer settling times or stronger swirl to obtain adequate radial migration of drops, although use of high inlet velocities must be balanced against the dangers of droplet disruption in the associated high shear fields. Accordingly, key features of the design are:

- an enlarged feed injection section, which allows a high degree of spin to be achieved by gradual acceleration through the reducing section rather than directly driven by a high velocity inlet stream

- a large overall length:diameter ratio, to provide adequate residence times

- an involute type feed duct and taper section of only 1-2° included angle, to promote flow symmetry and in particular a fine stable core of reversed flow.

It should also be noted that discharged flow control is achieved by external valves, the bulk of flow emerging as "clean" water from the clear outlet, the rejected flow being set sufficient to ensure removal of the oil core and emerging as a mixture of oil and water.

The principal advantages of hydrocyclones for deoiling are the compactness and simplicity of the hardware. These and other features, including operational characteristics, will be illustrated with reference to the most widely exploited application of the technology to date - crude oil production. New areas of potential linked with the oil industry will be investigated, in particular as part of an oil spill treatment system. Applications in other industries will also be considered.

Oilfield Produced Water Applications

There is almost always a water phase associated with crude oil production, which may vary from a few percent at an early stage in an oil field's life to 80 or 90% as it nears exhaustion, and economics currently dictate that the water is removed from the oil and treated at or close to the production site. In the offshore environment in particular this means that there is a significant premium on flexible and compact water treatment facilities.

The principal commercial design of hydrocyclone deoiler is the Vortoil(TM), manufactured by Conoco Specialty Products. This comprises a liner which effects the functional geometry of the separator, as shown in Fig. 1, and a containment vessel which supports the liner and facilitates connection to the process and operation under pressure. As scaling criteria dictate that large flows are best treated by using hydrocyclone units in parallel, designs in which a number of liners are incorporated into a common pressure vessel have been developed, producing considerable savings in pipework and valving requirements. The "Multi" system, which can take up to 37 hydrocyclone tubes in one vessel, is illustrated in Fig. 2. Options to use 35mm or 60mm diameter tubes (measured at the widest point of the taper section) depend on the particular application. At a given pressure drop, whilst a 60mm unit has 2-3 times the capacity of a 35mm hydrocyclone (6), its efficiency may be slightly lower as the internal centrifugal force field is weaker. This may be recoverable if higher driving pressures are available.

The operational weight savings which can be achieved over conventional separation systems, like TPI (tilted plate interceptor) and IGF (induced gas floatation) units, are typically up to 90%. A 25,000 bpd (barrels per day)

Vortoil system, for example, has a flooded weight of only about 6.5 tonnes. Space requirements are also low and the combination of the modular construction of hydrocyclone systems and their insensitivity to orientation means additional units can be easily added as water production increases. This insensitivity also extends to motion, making them well suited to use on floating structures. Maintenance needs are minimal as there are no moving parts, no build up of residues and the internals are constructed from erosion and corrosion resistant materials.

Operation and Performance

Further features of deoiler hydrocyclones are exemplified by considering their operational and performance characteristics. Figure 3 shows a simplified diagram of an oilfield production separator system incorporating hydrocyclones, where the required pressures are supplied by the process. The produced water stream coming from the first stage separator (3-phase knock out vessel) is regulated by level control within the first separator using valves beyond the hydrocyclone unit. This eliminates any possible problems due to droplet breakup through upstream control valves, a difficulty competing low pressure separators cannot avoid. The balance between the discharged flows from the hydrocyclone is maintained by keeping the pressure drops between the inlet to reject and inlet to clean outlet in a constant ratio (7). Figure 4 shows a typical relationship between flowrate through a 14 liner 35mm Vortoil and the larger of these pressure drops (by a factor of 7:4), that to the reject. The 1.5% reject ratio refers to the fraction of the feed flow emerging from the reject. So long as this flow remains above a critical minimum below which the stable reversing core breaks down, separation is independent of reject ratio providing it also exceeds the amount of oil to be separated (5,8). With oil levels in produced water typically in the range of a few hundred to a thousand ppm, the usual 1-2% reject ratio used can accommodate fluctuations above these concentrations without adjustment. If higher reject flows are required, these can be obtained by increasing the driving pressure drop, or for more permanent adjustment by using a larger diameter reject orifice.

A flowrate against oil removal efficiency curve for the same system is given in Fig. 5 under field conditions. As throughflow increases, separation rises to reach a plateau condition which is sustained over a considerable flow range. The fall in performance at high flowrates was ascribed to process pressure limitations being inadequate to drive the reject flow in this instance, but ultimately separation may also be restricted by an increased tendency for droplet break up to occur. Operating ranges for single liners will be of the order of 50-165 1/min (455-1500 bpd) for 35mm units and 130-435 1/min (1200-4000 bpd) for 60mm units, at inlet to reject pressure drops of 1-15 bar. Minimum values of 4 and 6 bar respectively are usually recommended to allow some operational flexibility, maximum values around 30 bar represent a drop stability limit.

Clean stream discharges with <40 ppm oil (i.e. within the current UK and NW European offshore limit) are consistently achieved by hydrocyclones, best performance being obtained when the process liquids are hot, the crude is

light and the produced water very saline (i.e. density difference is high) and the dispersion coarse. As a general guide, particle removal efficiencies for 5-10 μm drops are around 50%, so dispersions around this size will be difficult to treat. Enhancement options might include the use of chemicals to aid pre-feed coalescence, and typically, hydrocyclones are found to require much lower dosage rates to obtain adequate separation than do conventional separators. If plenty of pressure is available, an alternative may be passing the flow through other hydrocyclones connected in series. Automated control of such systems has been demonstrated (9), which included diversion of slugs into a holding tank.

Although deoiling hydrocylones cannot unaided deal with slugs of oil because of their low residence time (2 seconds or less), this is balanced by their ability to achieve full efficiency immediately, either on start up or when recovering from upstream upsets.

Contaminant phases, gas and solids, do not appear to adversely affect the oil/water separation process so long as their concentrations are not high. Laboratory tests with free gas contents of up to at least 20% by volume in the feed have shown a restricting effect on the liquid flow at the reject where the gas emerges (10). The general lack of such problems in the field implies that the main production knock out vessel efficiently removes free gas from the produced water stream and that gas evolution due to the pressure drops across the hydrocyclone is not substantial within the separator itself. Indeed, the phenomenon of dissolved gas coming out of solution after the pressure let down through the hydrocyclone has been significant enough in some cases to make it worthwhile putting a small tank beyond the clean stream outlet to obtain a secondary oil separation effect of the gas floatation type. Heavy solids, even when oil wetted, tend to be scrubbed clean by the cyclonic action and emerge with the bulk of the water phase. Deoiler geometries with an additional solids take-off facility to provide 3-phase separation have been suggested (11), but experience shows the oil/water separation effect may be compromised by such modifications (12).

Recent and Future Developments

Taken together then, the combination of features which the deoiling hydrocyclone offers - compactness, flexibility (with regard to flowrate and orientation), efficiency and minimal operator attention - makes it an ideal separator for offshore produced water treatment. This is particularly so in the expanding subject of marginal field exploitation where large fixed platforms are inappropriate because of small reservoir size or great water depth. Floating, sub-sea and small unmanned satellite production systems are the kind of options being developed and these provide further potential for hydrocyclones. Their insensitivity to motion has already proved a significant advantage for water treatment on Tension Leg Platforms like Hutton in the North Sea (8) and their ability to withstand high pressures (a "900 ANSI" rated unit is currently available) meets the anticipated need for separators which can cope with wellhead shut-in pressures in the sub-sea environment (15). Interest for onshore production applications is also building, with a number of units already in operation.

In installations where there is insufficient feed pressure a pumped system is required. The potential for the break up of oil droplets to unrecoverable sizes in conventional centrifugal pumps means low shear progressive cavity type pumps are favoured (13, 14). However, if process drop sizes are already small or separation requirements undemanding, the reliability and low cost of centrifugal pumps may be more important.

The potential to provide effective treatment of heavy oils has also been demonstrated for steam flood production conditions, although the problems of superheated produced water flashing to steam within the hydrocyclone had to be overcome by raising back pressures (15).

New developments of the oily water hydrocyclone itself are being essentially directed at providing lower pressure drop and higher efficiency operation (7). The main objective of the low pressure concept is to allow adequate separation to be achieved in conjunction with a single stage centrifugal pump. The intention of the high efficiency design is to increase the hydrocyclone's capability to deal with difficult separations, especially to reduce further the need for chemicals.

Application to much higher oil contents has also been pursued. A modified Vortoil unit is being field tested in California as a primary separator dealing with water cuts of 60% or more. The function of the unit is to extend the productive life of the field by both concentrating the oil phase and cleaning the water phase such that existing over-stretched production equipment can meet the appropriate discharge specifications. This type of "pre-separator" concept could have considerable use in aging oil producing areas, as production separator design capabilities for water are exceeded.

This expansion of the deoiling hydrocyclone's range imparts considerable stimulus to applications outside the sphere of oil production.

Oil-Spill Applications

The amount of oil released into the marine environment in connection with its transportation is at least an order of magnitude greater than due to its production (1). A significant fraction of this release is as crude oil spills at sea. These can quickly develop into stable and very thick sea water in crude emulsions due to wave action and are commonly referred to as "chocolate mousse". Chemical dispersants become progressively less effective as slick viscosities increase and collection methods are then adopted (17). However, chocolate mousse can be 70% water (18) or more and additional large and variable amounts of free water tend to be removed with it in the recovery process. This means a considerable volume of the recovery vessel is devoted to carrying sea water and the difficult problem of shore based disposal of the mousse would still need to be addressed. A treatment concept is put forward in which the material collected is first mixed with demulsifier to break the mousse and the resulting oil/water mixture fed to a bank of hydrocyclones to achieve a separation, concentrating the oil phase for possible re-use and allowing the water to be immediately discharged back to the sea (Fig. 6).

This 2-stage process has been investigated by laboratory separation tests of hydrocyclones with a simulated weathered crude/water/demulsifier mixture, at the University of Southampton, complemented by pilot scale tests working directly with batches of artificial mousse, at the BP Research Centre, Sunbury (UK). Tests were based around a 38mm hydrocylone separating a 10% oil in fresh water system with mean drop sizes around 100 μm and demulsifier levels averaging 670 ppm (19). Results from the laboratory programme, Fig. 7, show the importance of the reject or split ratio in determining the required operating condition which maximises the product quality of both discharge streams. It can be seen that 70% of the oil can be concentrated in a stream which is only 15% of the feed flowrate, leaving a water stream with 0.4% residual oil.

The acceptability of discharging even this small amount of oil at the spill site will clearly be an issue. However, an additional hydrocyclone stage bringing oil contamination down to a few hundred ppm might be a viable option, particularly as low presure drops were a consideration in the design of the hydrocyclone tested, inlet to oil stream being ~3.5 bar and inlet to water stream being ~2 bar for a working flowrate of 100 l/min in the optimum geometry. This throughput also appeared to be an upper limit in terms of efficiency as well, the high demulsifier levels resulting in a very low oil/water interfacial tension (0.0015 N/m) and consequent poor droplet stability characteristics.

Commercial interest has been shown in an oil-spill clean up vessel with processing rates as high as 33,000 l/min. This could be treated in a single pass hydrocyclone array with an estimated operating weight of 120-150 tonnes. Air portability may also be a consideration for such systems and dry weights are only fractionally lower that operating weights, as separator inventories are small.

Other Applications

The following listing represents an overview of the range of oily water separation problems which have been identified as offering potential for hydrocyclones based on investigations carried out by Conoco, often including trials with a mobile test unit. Like the oil-spill application, however, the hydrocyclone may require additional equipment to achieve an acceptable solution.

Marine applications include bilge water and ballast water clean up on ships, although secondary polishing may also be required before discharge at sea (11) - the IMO limit on bilge water discharge in coastal waters is only 15 ppm. Use in association with the treatment plants which take oil slops from tankers is also envisaged and interest from similar oily waste disposal centres has been expressed.

Another applicable oil industry related separation need is the decontamination of wash water - from the washing of mud cuttings during drilling operations and from its process use in refineries and tank farms. The surface drainage treatment systems to these areas is another likely place to employ

hydrocyclones. Indeed, a unit has already been sold for deoiling ground water below an old tank farm site which is being redeveloped.

The mining industry has requirements for large scale processing of water wastes, often contaminated with organic solvents. In the future, there may also be applications based on the exploitation of oil shale beds, currently an uneconomic source of oil.

In petrochemicals, the typical requirement appears to be a recycling operational mode. This is illustrated in Fig. 8 for a project in an ethylene plant where the Vortoil installation is designed to reduce levels of wax and oil in a caustic solution, allowing it to be effectively re-used for decontamination of process gas streams. A similar type of separation function is needed for quench water treatment in the same plant.

In steel manufacture and working, process water becomes contaminated with quench oils. Both oil recovery and clean water discharge are objectives for separation equipment.

Dense liquid separation in hydrocyclones is also gaining momentum, with an onshore 115,000 bpd gas condensate dewatering facility fed by pipeline having been recently commissioned (Bass Strait, Australia).

Conclusions

Since the first commercial unit was delivered in 1984, the light dispersion hydrocyclone has rapidly established itself in the area of compact oilfield produced water treatment equipment, with nearly 4,000,000 bpd capacity installed or on order world-wide. It has already become the first choice technique for new offshore installations and is gaining a foothold for land-based production as well. Recent product developments are not only expanding the possible range of applications within the oil industry, but also helping to open up new areas of use - wherever a need exists to process large quantities of oily water. Work is going on to improve gas handling and ultra-fine drop separation and to combine deoiling hydrocyclones with dewatering units to give integrated, compact plant.

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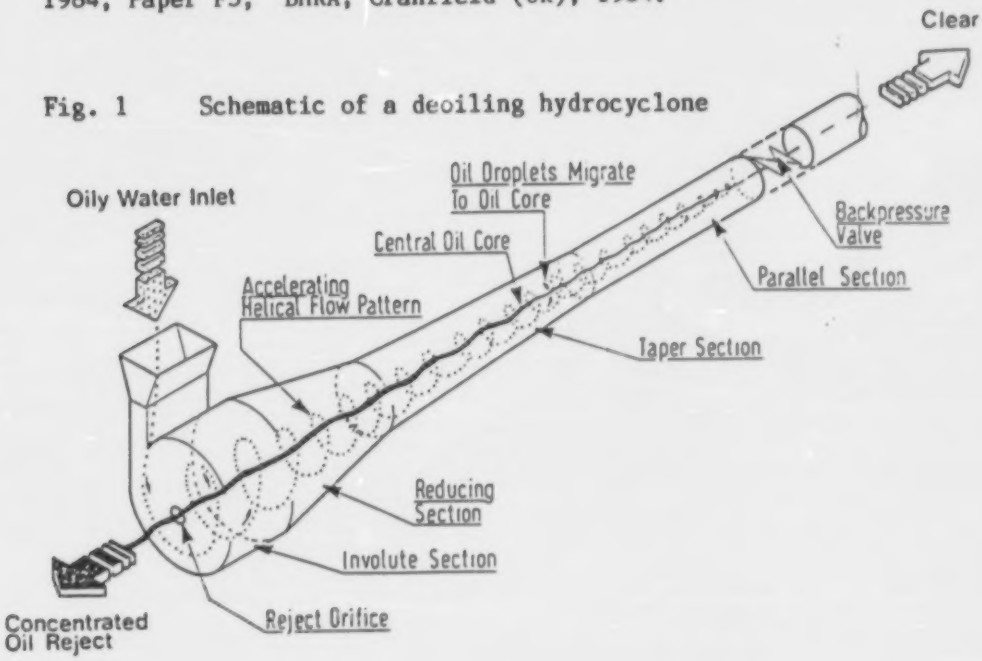

Fig. 1 Schematic of a deoiling hydrocyclone

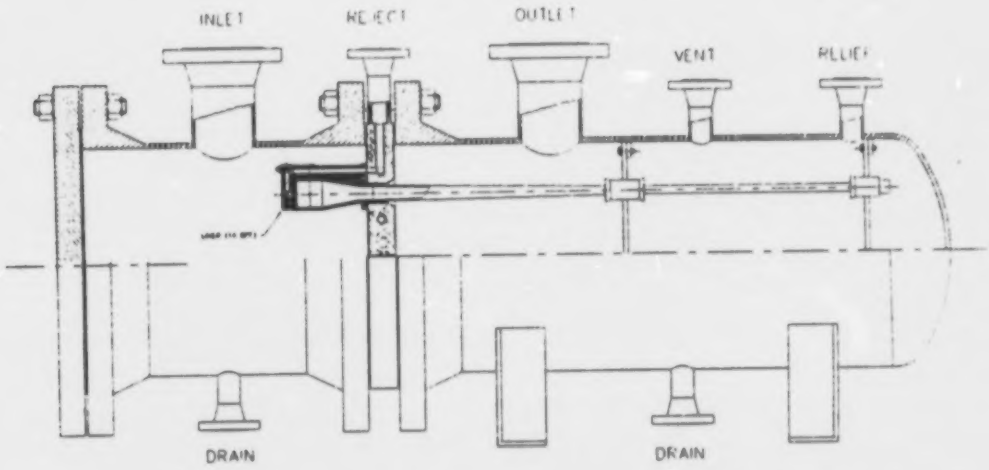

Fig. 2 Internal arrangement of a 14 liner "Multi" unit

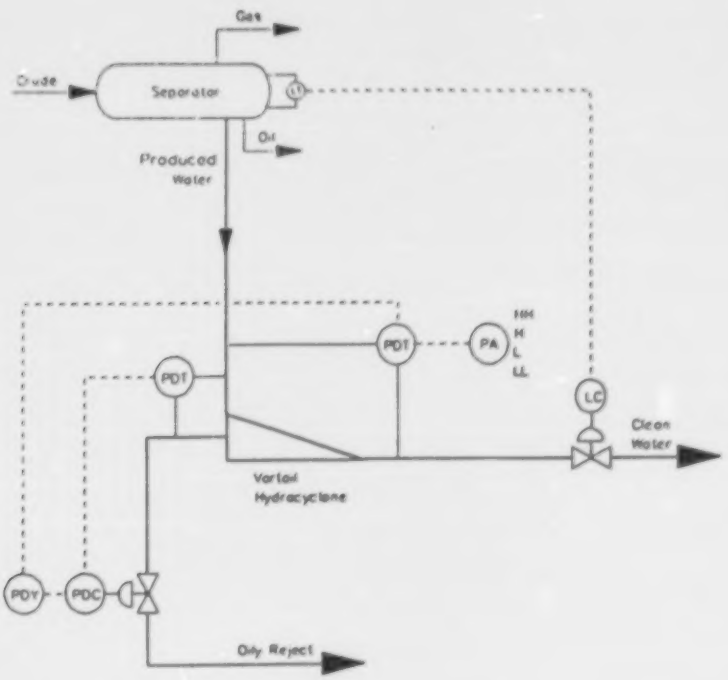

Fig. 3 Produced water treatment schematic

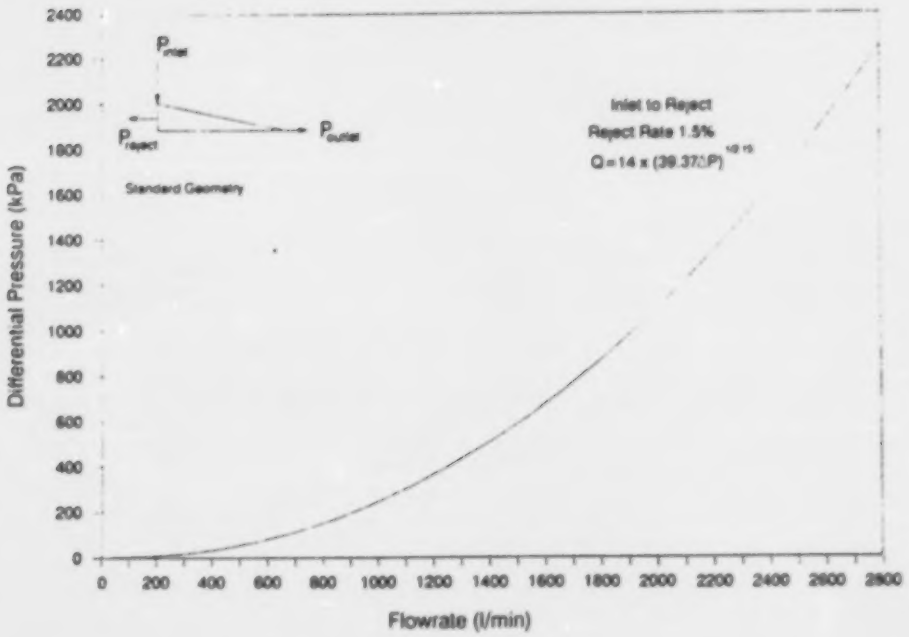

Fig. 4 Relationship between flowrate and differential pressure for a 14 liner 35mm Vortoil deoiler (100kPa = 1 bar, 100 l/min = 909 bpd)

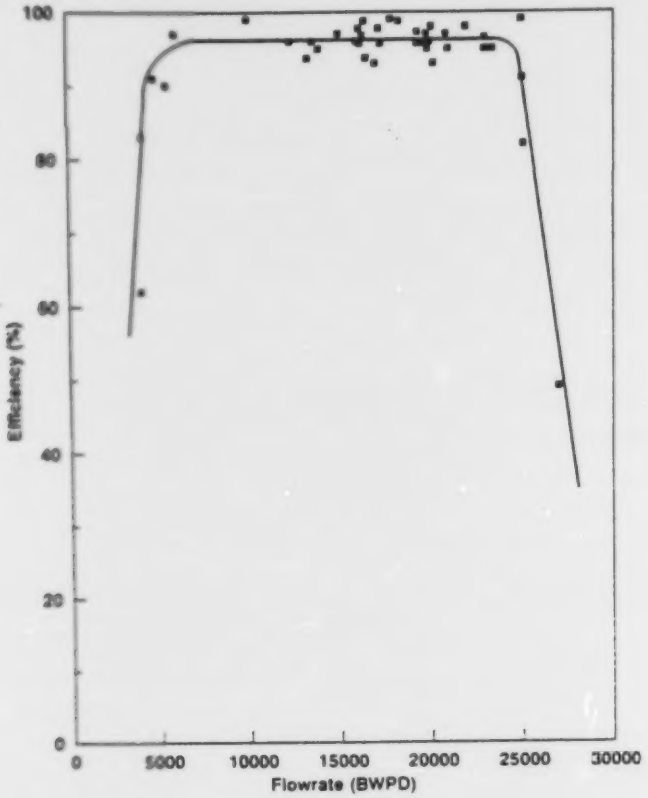

Fig. 5 Relationship between flowrate and efficiency of oil removal from the clean stream for a 14 liner 35mm Vortoil deoiler (1000 bwpd = 110 l/min)

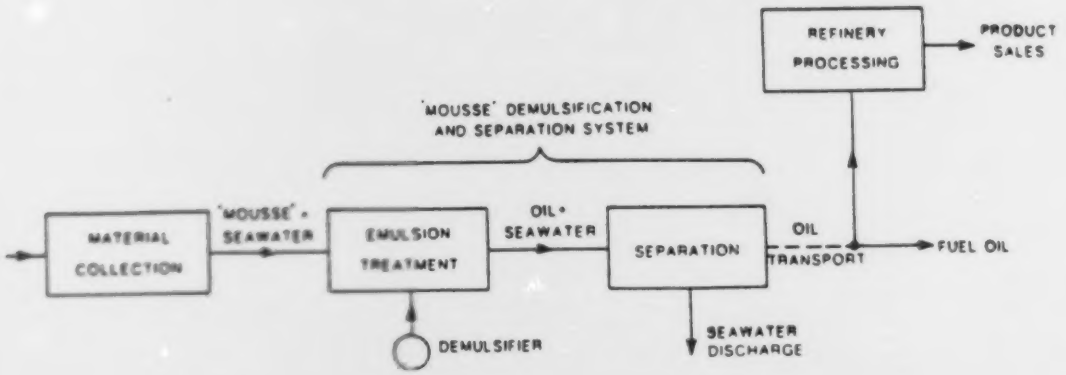

Fig. 6 Oil-spill treatment concept

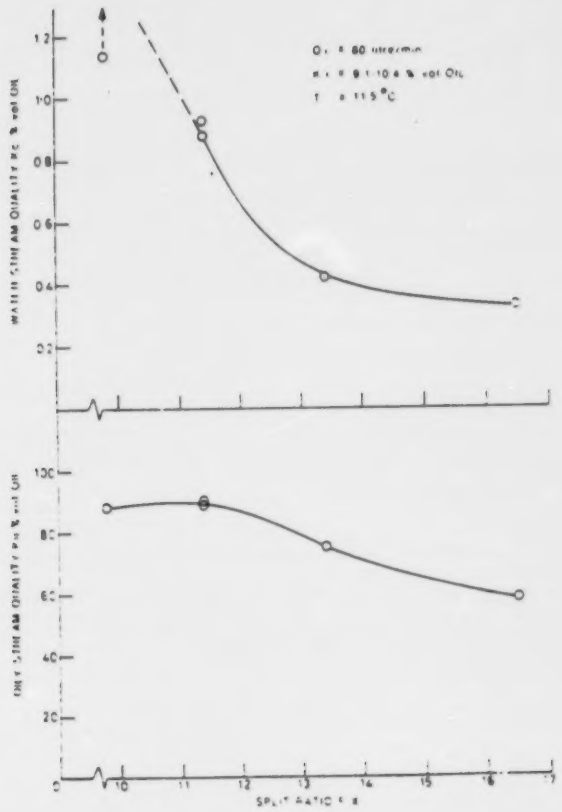

Fig. 7 Effect of split ratio on effluent quality (tests on simulated demulsified mousse)

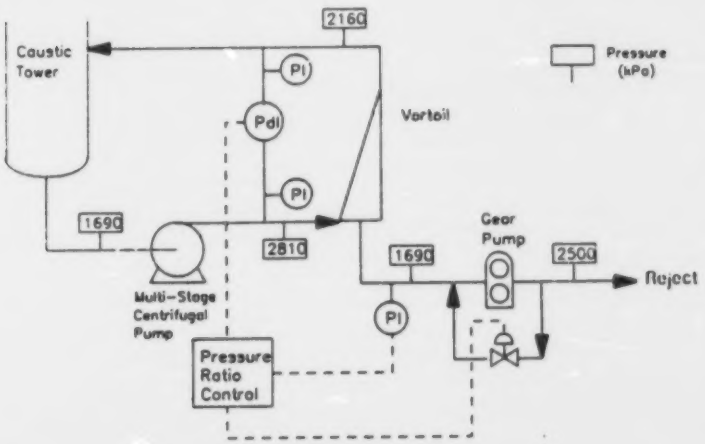

Fig. 8 Typical light contaminant regulating installation for a deoiling hydrocyclone - caustic tower loop in an ethylene plant

USE OF MINTEQ FOR PREDICTING AQUEOUS PHASE TRACE METAL CONCENTRATIONS IN WASTE DRILLING FLUIDS

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Introduction

Drilling fluids are used by oil companies when they drill wells to explore for oil and natural gas or to develop existing oil-fields. The drilling fluids are circulated in and out of the well-bore during drilling to control pressure, remove cuttings, lubricate and cool drill bits, and seal the geological formation being drilled. These activities result in the generation of more than 200 million barrels of waste drilling fluid/cuttings per year in the United States (1).

Freshwater drilling fluids consist of naturally occurring clays (bentonite), weighting materials (barite), water, and small amounts of other additives (lignosulfonates, lignite, caustic soda, lime). Measurable levels of heavy metals may be present in the formulated fluid or contributed by the drilled cuttings. These elements may be of environmental concern and it is important to understand their movement and fate.

The heavy metals are distributed between the solid and liquid phases of the waste. This distribution may be evaluated through total metals analysis, equilibrium modeling, speciation analysis, or leaching studies. Sorption to solids and the formation of insoluble precipitates control aqueous phase metal concentrations in most waste freshwater drilling fluids.

The purpose of this paper is to examine the availability of heavy metals in waste freshwater drilling fluids based on the application of MINTEQ, a chemical equilibrium model (2). Knowing the identity of the solid phases, aqueous phase concentrations of the elements can be predicted from thermodynamic data. Aqueous phase concentrations reflect the potential mobility of the element and are useful in transport modeling. The model predictions are compared with analytical results obtained in past characterization studies.

Background

Investigations into the fate and transport of constituents contained in waste freshwater drilling fluids have, to date, been limited to analyzing or manipulating waste samples to simulate behavior in the field. Little work has been performed to evaluate the mechanisms responsible for the observed behavior. However, while a strictly analytical approach does not provide the tools necessary for predicting or modifying behavior based on chemical properties, it does provide valuable information in regards to the waste samples tested and some general insight as to the expected behavior in similar wastes. A summary of previous freshwater drilling fluid work involving total metals analysis, speciation studies, batch leaching studies, and column leaching studies is provided as examples of this approach.

A laboratory study was performed to examine the chemical forms of solid phase arsenic, barium, chromium, and lead in drilling fluid wastes by sequential extraction following equilibration at an adjusted pH or ionic strength value (3). This provided insight as to the stability of the existing metal species.

Three active drilling fluid disposal sites located in Oklahoma were sampled. The pH or ionic strength of sub-samples were adjusted and the mixtures allowed to equilibrate. A sequential extraction procedure was then used to separate arsenic, barium, chromium, and lead into fractions defined as aqueous (water phase removal), exchangeable (KNO_3-extractable), adsorbed (H_2O-extractable), organically bound (NaOH-extractable), carbonate (EDTA-extractable), and residual (HNO_3-extractable).

The majority of each of the elements studies was found in the organically bound, carbonate, or residual fractions except for one waste which contained a major portion of the total barium in the exchangeable fraction. Generally, decreasing pH caused a shift from the more stable residual fraction toward less stable carbonate, organically bound, or exchangeable fractions. In no case was there a substantial release to the aqueous phase with changing pH or ionic strength. The significance of these results is that, with pH or ionic strength changes to be expected in the natural environment, there is not likely to be a major release of these elements from freshwater drilling fluid waste facilities. The lower pH values (<4) which might produce some impact are unlikely to occur because the wastes themselves have a large neutralizing capacity.

Barium was examined in 11 waste drilling fluid samples using a slightly different extraction method (4). This method partitioned the barium into water soluble, exchangeable, carbonate, iron/manganese oxides, organic, and residual fractions. The residual fraction accounted for 87.4 to 97.6 percent of the barium with only 0.1 to 1.7 percent in the soluble phase.

The Extraction Procedure Toxicity Test (EP Tox) (5) and Toxicity Characteristic Leaching Procedure (TCLP) (6) are batch extraction tests designed to determine the maximum leachate concentrations produced by a waste under a given set of test conditions. Both of these procedures evaluate

amounts of constituents available for leaching in an acid medium (co-disposal with municipal waste).

It may be argued as to whether a co-disposal scenario using acidic leaching solution validly represents the disposal environment of all wastes, especially alkaline waste drilling fluids. Nevertheless, the tests are required to meet regulatory guidelines, and are at least useful as worst case indicators of waste behavior.

The EP Tox Test has been performed on freshwater drilling fluid wastes (7,8). Both studies examined arsenic, barium, chromium, and lead with resulting concentrations less than the EP Toxicity limits for each constituent (Table 1).

TCLP analyses were performed and compared with proposed limits for both the liquid and solid phases of freshwater drilling fluid wastes (9,10). In no sample were the limits exceeded for any organic or inorganic constituent in the waste, including arsenic, barium, cadmium, chromium lead mercury, selenium and silver. Representative TCLP results are shown in Table 2.

It is apparent that when the EP Tox or TCLP extraction tests have been applied to waste drilling fluids, the resulting concentrations of constituents of interest were less than the suggested limits. Relative to drilling fluid disposal, metals appear to be stable under what might be considered worst case analyses. Although not representative, these extraction tests may provide a basis for comparison with other wastes.

Column leach tests involve placing the waste sample in a column, where it continuously contacts with a leaching solution at a flow rate either controlled by pumping or the permeability of the waste. Column tests may be considered to be more representative of field leaching conditions than batch extraction tests because of the continuous flux of the leaching solution through the waste. These tests are not often used, however, because of high cost and operational problems.

Drilling fluid wastes were subjected to column leachability tests to investigate the hydraulic conductivity (permeability) of waste drilling fluids, determine concentrations of chemical constituents in the column filtrate, and compare effluent constituent concentrations with initial total waste drilling fluid constituent concentrations as a measure of attenuation with waste drilling fluid (11). Concentrations of metals found in the column effluents were low relative to the total amount in the waste or associated soils (Table 3).

Actual monitoring at waste drilling fluid disposal storage or handling facilities would, or course, be the best method of determining the amount of metals migrating from these wastes. A few studies on disposal in pits have been performed and are summarized.

A study by Murphy and Kehew (12) examined salt-based drilling fluid disposal pits ranging in age from 2 to 23 years. Pore water in both the saturated and unsaturated zones were analyzed. While chlorides were found to leach from the pit, concentrations of metals were found to reach background levels within less than 100 feet of the pits. The restriction of constituents within the local area of these disposal pits was attributed to attenuation, mixing, and dispersion processes within the soils.

Henderson (13) studied eight sites throughout the United States and found that heavy metals, sodium and chloride tend to be elevated, relative to background, in subsurface soil locations in or near pits or impoundments. However, constituents did not appear to migrate any appreciable distance away from these facilities, as evidenced by ground water data. Most high concentrations in subsurface soils collected in pit areas occurred in distinct layers with visible evidence of contamination. The only parameters showing definite evidence of vertical migration through subsurface soils were sodium and chloride.

From this combination of chemical analysis, speciation studies, leaching experiments, and field monitoring, the behavior of various inorganic constituents with waste freshwater drilling fluids may be elucidated. Arsenic, barium, cadmium, chromium, copper, mercury, nickel, and lead appear to strongly attenuated and/or present at insignificant total concentrations under the pH conditions (>7) which predominate this type of waste. Strontium was found predominantly in the aqueous phase although total concentrations were also near background.

From these studies, it is clear that metals within a drilling fluid waste may be acted upon by attenuating mechanisms which greatly decrease their environmental impact. In evaluating proper handling and disposal routes for freshwater drilling fluid wastes, we should not focus only on a total chemical characterization of the waste without addressing the actual fate of these constituents within the surrounding pit environment.

Measuring and regulating the chemical constituents in drilling fluid wastes in terms of total concentrations implies that each identified constituent will have an acute impact on the environment based on this total concentration but not on its availability. As a conservative approach to initially assessing environmental impact or as a means of designing conservative treatment schemes based on dilution of the total constituents to acceptable levels, total concentrations are useful. However, one should be aware that many waste fluid constituents may be present in forms that make them unavailable chemically and biologically. The net effect of these attenuating mechanisms can be assessed by incorporating them within mathematical models which describe the bulk flow, dispersion, and chemical attenuation of these compounds within the soil/ground water matrix at a given site.

Equilibrium Modeling - MINTEQ

Several trace elements, such as As, Ba, Cd, Cr, Cu, Hg, Ni, Pb, and Sr, may be contributed to waste freshwater drilling fluids from drilling fluid components, make-up water, or drill cuttings.

Using estimates of waste composition, trace element estimates for each component (Table 4), and known or assumed solid phases (Table 5), the trace element distribution between the aqueous and solid phases were calculated (Table 6). A chemical equilibrium model (MINTEQ) was used to predict the distribution. MINTEQ is a thermodynamic equilibrium model that computes aqueous speciation, adsorption, and precipitation/dissolution of solid phases (2). The model has a large, well-documented data base that contains equilibrium constants and accessory data for more than 35 metals and 60 ligands. MINTEQ was developed to provide a predictive tool capable of performing screening-level analyses, but may be used to investigate potential impacts of different metal sources. MINTEQ is supplied by and obtains strong support from the U.S.E.P.A. (2).

A waste drilling fluid contains an element of interest in proportion to its contribution to the total waste volume. Freeman and Wakim (1) reported that the average drilling pit in the United States in 1985 stored approximately 827,000 liters of waste fluids. Liquids and solids made up about 90 percent (744,300 liters) and 10 percent (82,700 liters) of this volume, respectively. Based on a 1,700 meter deep well with a diameter of 20.3 centimeters, about 5.9 percent (48,800 liters) of the solids would be comprised of cuttings with the remaining 4.2 percent (35,700 liters) being the drilling fluid solids. The drilling fluid solids can be further divided according to average component usage for a clay-lignosulfonate fluid of barite-69%, clay-26%, chrome lignosulfonate-2%, lignite-1.5%, and caustic soda-1.5%. The result is a component summary for an average drilling fluid waste with components reported in mg/kg dry weight after adjustment for solid densities (Table 5).

Solid phases for equilibrium modeling were based on known or assumed species. Barium is added to drilling fluids as the barium sulfate. Chromium is added as chrome lignosulfonate in its trivalent form and would be expected to precipitate as chromium hydroxide at the average pH of waste drilling fluids. Montmorillonite (bentonite) elements (Si,Fe,Al) are assumed to be present as relatively inert oxides since bentonite is not in the MINTEQ data base and would not be expected to dissolve. All of the starting solid phases and dry weight concentrations are listed in Table 5.

This information was provided as input to MINTEQ at a pH of 8.3 and redox potential (Eh) of 0 volts. The resulting aqueous solid phase distribution is shown in Table 6 along with results of analyses from field collected waste drilling fluids (9). Of the metals examined, only Ni was indicated as existing predominately in the aqueous phase while As, Ba, Cd, Cr, Cu, Hg, Pb, and Sr were predicted as mineral phases. Results were consistent with chemically analyzed aqueous and solid phases from waste drilling fluids, with the exception of Ni being insoluble while a significant portion of the available Sr was soluble.

Conclusions

Using reasonable geochemical assumptions, MINTEQ is an effective screening tool for predicting the behavior of inorganic constituents within waste freshwater drilling fluids. Agreement between modeling results and average measured constituent concentrations is reasonable. This suggests that the mechanisms represented within MINTEQ are geochemically sound when applied to these wastes. Therefore, examination of these potential soluble and solid components provides insight into the chemical behavior of these complex wastes. This information will be valuable in evaluating past and current waste disposal practices. Modeling these systems may also be useful in designing drilling fluids to minimize constituent mobility.

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TABLE 1

Average EP Toxicity results for freshwater drilling fluid wastes

Study	Number of Samples	Arsenic (mg/L)	Barium (mg/L)	Chromium (mg/L)	Lead (mg/L)
Deeley (7)	3	0.0118	1.22	0.62	0.31
Canter et al (8)	5	0.043	15.3	0.21	1.77
EP Toxicity Limit	-	5.0	100	5.0	5.0

TABLE 2

Average TCLP results for freshwater drilling fluid waste solids

Study	Number of Samples	Arsenic (mg/L)	Barium (mg/L)	Chromium (mg/L)	Lead (mg/L)	Mercury (mg/L)
API (9)	19	0.0002	1.45	0.21	0.12	0.0002
EPA (10)	21	0.008	1.37	0.11	0.20	0.0007
TCLP Limit	--	5.0	100	5.0	5.0	0.2

TABLE 3

Average percentage attenuation of inorganic compounds within waste drilling fluid columns

Component	Average Attenuation %
Arsenic	97.1
Barium	99.8
Beryllium	99.0
Chromium	95.0
Cobalt	99.8
Copper	95.5
Lead	99.8
Molybdenum	85.3
Nickel	96.5
Potassium	95.3
Sodium	49.7
Strontium	95.8
Vanadium	74.3

TABLE 4

Average concentrations of elements in drilling fluid

Element	Water[1]	Cuttings[2]	Barite[3]	Clay[4]	Chrome Lignosul.[5]	Lignite[6]	Caustic[7]
Si(mg/kg)	7	206000	70200	271000	2390	2390	339
Fe(mg/kg)	0.5	21900	12950	37500	7220	7220	0.04
Al(mg/kg)	0.3	40400	40400	88600	6700	6700	0.013
Mg(mg/kg)	4	23300	3900	69800	5040	5040	17800
Ca(mg/kg)	15	240000	7900	4700	16100	16100	5400
K(mg/kg)	2.2	13500	660	2400	3000	460	51400
Na(mg/kg)	6	3040	3040	11000	71000	2400	500000
Ba(mg/kg)	0.01	158	590000	640	230	230	0.26
Sr(mg/kg)	0.07	312	540	60.5	1030	1030	105
Pb(mg/kg)	0.003	37	685	27.1	5.4	5.4	0.004
Cr(mg/kg)	0.001	183	183	8.02	40030	65.3	0.00066
Cu(mg/kg)	0.003	22	49	8.18	22.9	22.9	0.039
Ni(mg/kg)	0.0005	15	3	15	11.6	11.6	0.09
As(mg/kg)	0.0005	3.9	34	3.9	10.1	10.1	0.039
Co(mg/kg)	0.0002	2.9	3.8	2.9	5	5	0.00053
Cd(mg/kg)	0.0001	0.08	6	0.50	0.2	0.2	0.0013
Hg(mg/kg)	0.0001	0.12	4.1	0.12	0.2	0.2	5

[1]Average elemental composition of freshwater - reference 14.
[2]Average elemental composition of sedimentary rocks - reference 15.
[3]Average elemental composition of barite - reference 16. Al and Na assumed identical to cuttings average.
[4]Average elemental composition of bentonite clay - reference 17. Ni, As, Co, Cd, and Hg assumed identical to cuttings average.
[5]Average K, Na, and Cr composition of chrome lignosulfonate - reference 18. Other elements assumed identical to lignite.
[6]Average elemental composition of lignite - reference 19.
[7]Average elemental composition of caustic based on production from sea-salt by mercury cell electrolysis resulting in 5 ppm Hg concentration - reference 15 and 20.

TABLE 5

Initial solid phases considered during MINTEQ modeling of waste freshwater drilling fluid

Element	Solid Species	Concentration (dry weight) mg/kg	percent
Ba	$BaSO_4$	332000	33.6
Si	SiO_2	272000	27.4
Ca	$CaCO_3$	248000	25.1
Al	Al_2O_3	68800	7.0
Mg	MgO	26700	2.7
Fe	Fe_2O_3	22900	2.3
K	KOH	8610	0.9
Na	NaOH	8530	0.9
Sr	$SrCO_3$	528	<0.05
Cr	$Cr(OH)_3$	462	<0.05
Pb	$PbCO_3$	314	<0.05
As	$Ba(AsO_4)_2$	60.5	<0.05
Cu	CuO	32.3	<0.05
Ni	$Ni(OH)_2$	13.0	<0.05
Cd	$CdCO_3$	3.16	<0.05
Hg	$HgCO_3$	1.86	<0.05
			100

TABLE 6

Comparison of MINTEQ results and chemical analyses for an equilibrated freshwater drilling fluid waste

	MINTEQ			Average Analysis[1]		
Element	Aqueous (mg/l)	Solid (mg/kg)	% Solid	Aqueous (mg/l)	Solid (mg/kg)	% Solid
As	<0.000001	83	100	0.06	3.3	98.2
Ba	4.4	63000	100	4.0	1800	99.8
Cd	0.00068	0.56	99.9	0.0018	0.069	97.4
Cr	0.00070	75	100	0.44	12.1	96.4
Cu	0.00014	16	99.2	0.069	6.01	98.9
Hg	0.0039	0.40	99.0	0.000035	0.015	99.8
Ni	2.6	0	0	0.065	6.7	99.0
Pb	0.55	78.1	99.3	0.83	25.8	96.8
Sr	0.87	99	99.1	63.7	103.7	38.6

[1]Reference 9

USING OILY WASTE SLUDGE DISPOSAL TO CONSERVE AND IMPROVE SANDY CULTIVATED SOILS

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Introduction

The development of heavy oil deposits in western Canada must increase substantially in the near future to replace diminishing supplies of light to medium crude oil if Canada is to attain energy self sufficiency. Heavy oil development is being furthered by two upgraders, one completed in 1988 at Regina, Saskatchewan and one still under construction at Lloydminster, on the Alberta/Saskatchewan border, to eventually provide a combined capacity to process 16,000 m^3 of heavy crude per day. To improve heavy oil recoveries, beyond the 5 to 10% yield feasible with conventional pumping, so-called "enhanced oil recovery" (EOR) methods (such as steam injection, fireflood and alkaline-polymer flooding) will have to be used more in the future. These EOR methods are more effective in pushing heavy oil out of underground formations, but unfortunately they also produce much higher volumes of sludge and other non-refinable wastes.

The disposal of oily wastes generated during field production has become a major environmental issue in heavy oil development. Historically, these wastes have been spread on lease and rural roads but the practice of "road oiling" can no longer accommodate the growing quantities of waste materials. Furthermore, provincial and federal environment agencies are concerned that runoff from oiled roads could eventually pollute rural drinking water supplies with undesirable chemicals such as polynuclear aromatic hydrocarbons (PAHs). Without the means for waste handling and disposal in a more acceptable and sustainable manner, waste management could create environmental problems that would ultimately slow or impede the development of the heavy oil resources in Canada.

To assess if heavy oil production wastes can be used to conserve agriculturally marginal sandy soils a field and laboratory study, funded by the Government of Canada under the Interdepartmental P.E.R.D. (Panel on Energy R&D) Programme, was jointly initiated in 1986 by Environment Canada and Agriculture Canada. The project takes a novel approach to research on landfarming with oily wastes by focusing on the potential for improvement of

highly erodible and infertile cultivated soils through application of waste sludge and fertilizer rather than to emphasize industrial disposal aspects which have invariably led to attempts 'to get rid of the largest possible volume of wastes on the smallest and nearest available land area' with little regard for soil conditions and potential agricultural benefits. Consequently, the primary objectives of the present study were to: (i) evaluate if productivity and structure of marginal sandy land can be enhanced by incorporation of organics contained in heavy oil waste sludge; (ii) determine if these oily wastes can induce more stable aggregation of loose surface particles and thereby reduce the high susceptibility of sandy cultivated soils to degradation by wind erosion; and (iii) determine optimum loading and agronomic conditions for sludge use to improve soil quality and stabilize crop yields without excessive contamination of crops and soils with undesirable chemicals; so as to facilitate the development of an environmentally sound and agriculturally beneficial disposal option.

Materials and Methods

In late June and early September 1986 two plot experiments were established on a level 2.0 ha (5 acres) area of Meota loamy sand, a Black Chernozem (or Udic Boroll according to the US system of soil taxonomy), located 10 km southeast of Maidstone, Saskatchewan. This member of the 'Meota' soil association had developed on sandy glacial alluvial-lacustrine deposits that have been re-worked by wind. Major properties of the 0-10 cm and 10-30 cm depth of the eroded drift deposit, viz. the 2 soil segments to be primarily affected by oily waste applications, are listed in Table 1. The 'FC' experiment is a fallow-wheat-wheat rotation where the sludge was only applied in the fallow phase i.e., on June 25, 1986. The 'CC' experiment was planned to be a continuously cropped cereal rotation where the sludge was initially applied on September 3, 1986 and was to be re-applied in future years, in fall, after the grain harvest, whenever deemed suitable. Unfortunately, initial oil contents in soils from sludge-treated plots of the 'CC' experiment were, inadvertently, several fold higher than targeted due to extreme variability in oil content of sludge from one truckload to another at time of application. Due to the resultant abnormally high and persistent phytotoxicity in all sludge-treated CC plots only results from the FC experiment will be presented in this paper. However, some data from the CC experiment were included in an earlier project report by Biederbeck and St. Jacques (3) and copies of this report are available, upon request, from the authors.

Three sludge application (designated by 1st and 2nd digit of the 4 digit plot treatment code as 00=none, 01=300 and 02=600 tonnes/ha) and fertilization rates (designated by 3rd and 4th digit of the code as F0=none, F1=150 kg N + 15 kg P + 24 kg S, and F2=300 kg N + 30 kg P + 48 kg S/ha) were used in the fallow plots in trying to reach the targeted waste loadings of 1.0% and 2.0% oil in soil (wt/wt), respectively. The planned waste loading was based on an average composition of 5% oil + 65% brine + 30% solids (VFS) in the EOR waste sludge being hauled to the site from the Husky Oil Ltd., Golden Lake Waseca Fireflood Pilot Plant #4 near Maidstone. The ratio between the three

nutrient elements added as fertilizer, i.e., N/P/S=100:10:16, and the total amount of fertilizer applied were selected such that they would optimize microbial conversion of hydrocarbons to soil humus-type materials rather than maximizing oil degradation and CO_2 evolution to effect a possible net loss of soil organic matter. All 9 sludge x fertilizer combinations were replicated 3 times on a total of 27 plots, each being 4 m wide and 14 m long. First the fertilizer was broadcast, then the EOR sludge was applied and simultaneously incorporated to a depth of 10 cm with a specially modified rotovator pulled by a tractor and connected through its Bowie pump and 3" hose to a tank truck running alongside. Due to the large volumes of waste sludge required (e.g., 30 litres/m^2 for the '01' rate), the '02' application rate necessitated 2 consecutive passes with the applicator-rotovator about 16 hours apart to prevent any possibility of lateral movement of oily wastes away from the area of soil incorporation. In mid-October 1986 and 1987 all plots received fall tillage by working the surface soil with a heavy duty cultivator to a depth of 10 cm to improve aeration and soil mixing. On May 15, 1987 and also on May 10, 1988 all plots and the surrounding area were seeded to hard red spring wheat, cv. Katepwa, at a rate of 86 kg/ha (77 lb/ac). In 1989 all plots were summerfallowed by cultivating and rototilling twice to 10 cm soil depth. Tillage and seeding operations were performed with standard farm machinery. No fertilizer was applied to any plots during the first crop year (1987) and during the second fallow phase (1989) but prior to stubble-cropping fertilizer was re-applied in April 1988 at the 'F1' and 'F2' rates as per the original treatment plan and thereafter all plots were roto-tilled. No herbicides were used on any plots until October 1987 to facilitate proper evaluation of the herbicidal effects exerted by the soil-incorporated hydrocarbon residues. Thereafter herbicides were applied but still rather sparingly.

Soils in all 27 plots were sampled hydraulically to 120 cm depth (2 cores/plot and 5 depth segments/core) just before the fertilizer and oily sludge applications in late June 1986 and again prior to wheat seeding and after grain harvesting in 1987 and 1988 and also in spring and fall of 1989 for routine physical and chemical analyses. The surface layers (0-10 cm) were sampled more often, at least initially, for soil structural, biochemical, microbiological and hydrocarbon analyses. Plant production was determined by sampling twice during each crop year. When the wheat was flowering, around the end of July, two 1.0 m^2 samples were cut in each plot to count the weed population and the wheat stand density and to measure the vegetative dry matter (DM) production by the wheat crop. At full maturity, between early and mid-September, duplicate 1.0 m^2 samples of wheat were cut in all 27 plots for subsequent drying and hand-threshing to determine grain and straw yield and also major parameters of grain quality.

All hydraulically cored soil samples and also the surface samples collected manually for dry aggregate analysis were air dried and stored at ambient temperature until analyzed, while those surface samples destined for waterstable aggregate, hydraulic conductivity, microbiological and hydrocarbon analyses were always stored field moist at 0°C. To determine the amount of oily residues remaining in the sludge-treated soil a composite sample was taken from six locations in each plot and representative

subsamples were periodically shipped to a commercial laboratory, i.e., Norwest Labs in Edmonton, Alberta, where the oil and water were separately recovered by hot toluene extraction according to the method of Dean and Stark (16). To assess sludge treatment effects on one major phase of soil structure the state of the secondary, field or dry aggregates was periodically measured. Triplicate composite samples were taken from six locations in each plot and after drying the soil was mechanically separated into various aggregate sizes by rotary dry sieving (5) because the susceptibility of soil to erosion by wind is closely related to the size distribution of its dry aggregates (7). The primary or waterstable aggregates represent another important aspect of soil structure. To determine the size distribution of these aggregates duplicate composite samples were taken from four locations in each plot and after screening (< 8 mm) the field moist soil (25 g subsamples) were wetted and the disruptive force of water was used for aggregate separation by the wet sieving technique as described by Kemper and Chepil (7). For ease of evaluation of oily waste addition effects the aggregation data were expressed in the form of a single parameter per sample by calculating the geometric mean diameter (GMD) which is considered to be the most reliable index of waterstable aggregation in soils. To assess the effects of sludge incorporation on the rate of water movement through soil three undisturbed cores of topsoil were taken manually in each plot with 15 cm long x 5 cm diameter aluminum tubes. All tubes were tightly closed with plastic caps for transport to the laboratory where the saturated hydraulic conductivity was measured by the constant-head method as described by Klute (8).

Heterotrophic microbial activity was assessed by determining rates of soil respiration. Two subsamples from the composite surface sample taken from six locations in each plot were placed in Biometer flasks (1) and incubated at field capacity moisture and 21°C for 14 days. The amount of CO_2 evolved was collected in NaOH and measured at appropriate intervals by titration. The population levels of major types of heterotrophic microorganisms were determined on the same composite surface samples, as taken for respiration and hydrocarbon analyses, by using the dilution plate count method. Aerobic bacteria and actinomycetes were enumerated with spread-plate techniques on soil extract agar and filamentous fungi and yeasts on rose bengal-streptomycin agar as described by Biederbeck et al (2).

All data from soil and plant analyses were processed statistically and least significant difference (LSD) values were calculated and used to test for significant differences between treatment means.

Table 1. Major physical and chemical properties of Meota soil at PERD project site near Maidstone, Saskatchewan, prior to oily waste sludge incorporation in 1986.

Soil Property	Depth, cm 0-10	10-30
Texture:		
Sand, %	79.9	81.9
Silt, %	8.7	8.6
Clay, %	11.4	9.5
Texture class	loamy sand	loamy sand
pH*	5.8	6.1
Electrical conductivity*, mS/cm	0.54	0.26
Bulk density,§ g/cm^3	1.31	nd
Saturated hydraulic conductivity§, cm/hr	7.3	nd
Water content:		
At field capacity (0.033 MPa), %	11.8	7.5
At perm. wilting pt. (1.5 MPa), %	8.4	5.7
Cation exchange capacity, meq/100 g	49.7	nd
Water-extractable cations, µg/g soil:		
Na^+	1.45	1.23
K^+	5.47	3.38
Ca^{2+}	0.81	1.61
Mg^{2+}	1.80	1.48
Total N, %	0.184	0.114
Organic C, %	2.20	1.31
C/N ratio	12.0	11.5

* In saturation extract. § For 0-15 cm depth. nd=not determined.

Results and Discussion

Reasonably uniform incorporation of the EOR waste sludge was accomplished without difficulty, at both application rates, by running the blades of the applicator-rotovator at top speed (i.e., 550 rpm) while the tractor pulling the rotovator is travelling very slow (i.e, 0.59 km/h or 0.36 mph). Although there was more variability in toluene-extractable oil content of surface soil between treatment replicates than was apparent from visual examination of treated plots and although there were some unexplainable increases in soil oil content during the first winter (Table 2) the measurements of residual oil contents in our four year study were considerably less erratic than the corresponding results reported from some other oily waste landfarming studies (12, 15). Sludge incorporation changed the appearance of the Meota loamy sand as rotovating drastically lowered the density by 'fluffing up' the topsoil, particularly in the double roto-tilled 02 plots, and as oily waste admixture perceptibly darkened its color. Not all sludge-treated plots could

be manually soil sampled within 24 hours of oily waste incorporation for subsequent hydrocarbon analyses because the pungent odors and noxious vapors emanating from the soil surface made this task very difficult and unhealthy. Thus initial sampling was limited to the unfertilized 01 and 02 plots. The characteristic odor of this EOR sludge could still be detected on treated plots for the next 16 months. Thereafter, the odor only re-appeared immediately after any tillage operation.

Table 2. Effect of oily waste sludge incorporation and fertilization on content of toluene-extractable organics in Meota loamy sand.

Treatment code*	Sampling date							
	June+ 1986	Sept. 1986	May 1987	Sept. 1987	Apr. 1988	Sept. 1988	May 1989	Sept. 1989
	------	Extractable oil as % of dry wt. of soil§						-------
01FO	1.03	0.70	0.85	0.66	0.85	0.77	0.71	0.71
01F1	ns	0.56	0.99	0.84	0.75	0.75	0.66	0.74
01F2	ns	0.76	0.70	0.76	0.65	0.73	0.68	0.65
01 Mean	--	0.67	0.85	0.75	0.75	0.75	0.68	0.70
02FO	1.45	1.10	1.30	1.03	0.93	0.89	0.86	0.85
02F1	ns	1.20	0.99	0.96	0.98	0.86	0.86	0.79
02F2	ns	1.09	0.93	0.99	1.01	0.88	0.85	0.83
02 Mean	--	1.13	1.07	0.99	0.97	0.88	0.86	0.82

* Soil in untreated 00F0 control plots contained 0.093 and 0.087% extractable oily substances when sampled in June 1986 and April 1988, respectively.

\+ Samples collected June 26, 1986 i.e., one day after oily waste sludge incorporation.

§ All values are mean of 3 replicate plots/treatment at 0-10 cm depth.

ns = not sampled.

During the first 10 weeks after sludge incorporation the rate of loss of toluene-extractable oily materials from Meota loamy sand was high, averaging 32 and 24% for unfertilized 01 and 02 treatments, respectively (Table 2). Much of this initial rapid loss can be attributed to physical processes whereby some very light oil fractions move upward within the sandy soil and upon reaching the surface are readily lost to the atmosphere by volatilization and evaporation. Biological processes are the other major loss mechanism as the soil microbial population readily metabolizes the more easily degradable oily waste components and respires some oil-C as CO_2. Initially elevated rates of oily sludge biodegradation have also been found in several other studies (4, 13). Over the next three years there appeared to be no further decrease in residual oil content in any of the soils treated at the 01 rate and only an average decrease of another 19% in soils treated

with sludge at the 02 level (Table 2). These very low rates of waste oil degradation were certainly unexpected as they are consistently lower than biodegradation rates observed in other landtreatment studies (12, 17, 15, 13). The lack of biodegradation could be attributed, in part, to the occurrence of very severe drought conditions at the experimental site in 1987 and 1988 or, in part, to the coarse texture of the Meota soil since Skujins and McDonald (15) found that waste oil biodegradation in a semi-arid soil occurred only during short seasonal periods of favorable moisture and temperature conditions and as Rimmer and Al-Khafaji (13) emphasized that fuel oil degradation in soils decreased markedly with decreasing clay contents. At 3 1/4 years after incorporation of the EOR sludge 69 and 59% of the initially soil-contained oily materials were apparently still present in 01F0 and 02F0 plots, respectively (Table 2). However, based on the extensive decline in phytotoxicity of the sludge-treated soils, observed over the same 3-year period, it can be assumed that most oily residues in this sandy soil were attached by microorganisms and were biochemically modified or transformed but not to such an extent that they were rendered unextractable to toluene. The microbial transformation of hydrocarbons and eventual incorporation into soil organic matter was reported from several 'landfarming' studies (4, 15). Thus, in the current study oily waste incorporation had by September 1989 effected a 20 and 16% increase in total soil organic matter (based on soil-C data) over the initial level of indigenous organic matter before sludge application at the 01 and 02 rate, respectively. Addition of N+P+S fertilizer had no effect on waste oil degradation at the 01 sludge treatment rate, while at the 02 sludge rate there was, at least initially, a trend suggesting that fertilization had stimulated oil degradation (Table 2) but these fertilizer effects were not statistically significant. Some other investigators have also found that fertilization failed to increase oil degradation significantly (Odu 1978; Skujins & McDonald 1985) while many others have reported the opposite and strongly recommend fertilization (12, 18, 10, 13).

Neither initial fertilization in June 1986 nor fertilizer re-application in April 1988 had any significant effect on the size distribution of dry aggregates in sludge-treated or in control soils. Consequently, only results for those treatments that were sampled twice each year for dry sieving, viz. 00F0, 01F1 and 02F2, are shown in Table 3. These dry sieving analyses of secondary aggregation show that incorporation of EOR sludge, even at the lower 01 rate, was very effective in reducing the erodible fraction near the surface of the loamy sand for about 3 1/2 years, but 8 months later all differences had disappeared at both sludge rates.

At 11, 15 and 22 months after soil oiling the erodible fraction in sludge-treated plots was, on average, 16, 16 and 11% (of dry wt. of soil) lower, respectively, than in control plots (Table 3). The magnitude of these topsoil erodibility reductions effected through oily sludge incorporation, was considerably greater than those found by Biederbeck and co-workers (2) to have been effected after 12 years by different crop rotations on a Brown loam in southwestern Saskatchewan. This increase in stable dry aggregation was sufficient to render the sludge-treated soils completely resistant to wind erosion because thin layers of white, unoiled sandgrains, obviously blown

onto the dark-colored, oiled plots from the surrounding untreated land, were frequently observed, but no similar deposition of dark, oiled sand was ever detected on untreated soil downwind from any 01 or 02 plots. It must also be emphasized that for three years the erodible fraction in 02 plots was never lower than in 01 plots despite the initially about 50% higher oil content in the former plots (cf. tables 2 and 3). This implies that addition of more oil, than is necessary to attain an initial 1% concentration in soil, provides no additional benefits for erosion proofing of this loamy sand.

Table 3. Effect of oily waste sludge incorporation on erodibility of Meota loamy sand

Treatment code	Sampling date						
	May 1987	Sept. 1987	Apr. 1988	Sept. 1988	May 1989	Sept. 1989	May 1990
	--- Erodible fraction* as % of dry wt. of soil ---						
00F0	94.2	90.4	94.5	93.3	90.4	96.6	89.9
01F1	78.5	75.8	83.7	88.7	84.2	87.7	87.4
02F2	78.0	72.4	82.9	85.9	86.0	88.2	86.5

LSD (P=0.05) for treatment x date = 8.2%, n = 9.

* Proportion of particles < 0.84 mm as determined by rotary dry sieving of soil from 0-10 cm depth.

As noted earlier for dry aggregation, fertilization also failed to affect the size distribution of primary or waterstable aggregates. Hence only results from those treatments that were sampled more frequently for wet sieving are shown in Table 4. Sludge incorporation effected very large and very persistent increases in the mean diameter of waterstable aggregates in the sandy soil. Thus the GMD in the treated layer of 01 and 02 plots 11 months after waste oil admixture was 9- and 11-fold greater, respectively, than in topsoil from 00 plots. At 39 months after treatment GMD was still 6- and 4-fold above the control in 01 and 02 plots, respectively.

During the first two years after EOR sludge application the size of waterstable aggregates in the higher oil 02 plots was always significantly greater than in 01 plots (Table 4). Recently, Rimmer and Al-Khafaji (13) reported that additions of fuel oil have greatly increased the aggregate stability in structurally unstable Iraqi soils. As a result of the extensively increased size and stability of primary aggregates there is no doubt that the waste oil-treated Meota sand had also become very resistant to slaking and water erosion. However, it is possible that the wet sieving method may have greatly overestimated the actual stability of the 'binding together' of previously loose particles into aggregates in oily sludge-amended soils because the strong hydrophobicity of hydrocarbons remaining on the outer surfaces of most aggregates would tend to slow down or prevent entry of water into such coated aggregates. Thus the presence of oily

residues would considerably lessen the disintegrating force exerted by rapid and repeated water entry during the wet sieving action.

Table 4. Effect of oily waste sludge incorporation on waterstable aggregates in Meota loamy sand

Treatment code	Sampling date					
	May 1987	Sept. 1987	Apr. 1988	Sept. 1988	May 1989	Sept. 1989
	GM diameter* in mm					
00F0	0.37	0.62	0.77	0.72	0.37	0.48
01F1	3.27	3.36	3.15	3.97	2.68	2.90
02F2	4.17	4.51	4.12	4.64	3.19	1.93

LSD (P=0.05) for treatment x date = 0.90 mm, n = 6.

* Geometric mean diameter as determined by wet sieving of soil from 0-10 cm depth. GMD is an index of the state of aggregation.

Results from the dry and wet sievings clearly show that oily waste sludge incorporation markedly improved the structure of the loamy sand through greatly increased and more stable aggregation. Erosion, salinization, acidification and declining levels and quality of organic matter have been identified as the major sources of soil degradation in western Canada (6) with high wind and water erodibility and lack of organic matter being the predominant problems on sandy, cultivated soils. Considering the soil organic enrichments and structural (aggregation) improvements that can be effected with well-managed oily waste incorporation into cultivated fields it should be possible for EOR waste sludge management and disposal to make a very significant and beneficial contribution to future conservation of and sustained crop production on these sandy problem soils.

As expected, water movement within the surface soil was drastically reduced as the result of oily sludge incorporation (data not shown). Saturated hydraulic conductivity decreased from 7.3 cm/hr in control plots to 1.9 and 2.5 cm/hr in 01 and 02 plots, respectively, within one day of sludge application. Eleven months later conductivities were still similarly low in treated soils, but by 3 1/4 years after soil oiling the hydraulic conductivities in 01 and 02 plots had recovered to a level that was equivalent to about 80 and 40% of the rate of water movement in the control soil. Although the sludge applications caused extensive and rather persistent reductions in hydraulic conductivity of surface soil there was no serious interference with normal rates of water movement in this coarse textured soil (3).

Soil incorporation of massive amounts of organic carbon (i.e., from about 10,000 to 25,000 kg oil-C/ha), in the form of EOR sludge-contained hydrocarbons was expected to boost soil microbial populations and stimulate

heterotrophic microbial activity which can be readily determined by measuring the production of CO_2. Within 10 weeks of the sludge application respiration rates in unfertilized 01 and 02 plots were already 2.2- and 2.7-fold those of the corresponding controls, while CO_2 evolution by all fertilized and oiled soils, except for 02F2, was significantly greater than in fertilized controls (Table 5). However, eight months later respiration rates in all sludge-treated soils were greatly enhanced, now being 4.2- and 5.4-fold those of the respective controls in unfertilized 01 and 02 treatments. Thereafter, respiration rates in all sludge-amended soils decreased extensively (i.e., by a factor of 3 to 4) and then remained very close to control levels over the next two years.

Table 5. Effect of oily waste sludge incorporation and fertilization on rate of microbial respiration in Meota loamy sand

Treatment code	Sampling date				
	Sept. 1986	May 1987	Sept. 1987	Apr. 1988	Sept. 1989
	μg CO_2-C/g O.D. Soil*				
00F0	98	53	55	59	80
00F1	98	59	65	70	88
00F2	99	52	59	55	82
01F0	220	225	58	81	74
01F1	143	235	62	77	87
01F2	103	127	59	59	72
02F0	261	285	96	100	77
02F1	140	269	75	62	58
02F2	181	249	65	58	54

LSD (P=0.05) for treatment x date = 60 μg CO_2-C, n = 6.
* Cumulative CO_2 evolved during 14 days at FC and 21°C by soil from 0-10 cm depth.

It must be noted that the period of maximum soil microbial CO_2 production in most sludge-treated soils, i.e., May 1987, did not coincide with the period of maximum oil biodegradation, i.e., June to September 1986. An initial decline or lag in respiration, after oil addition to soils, followed by a rapid rise and later slow decline in activity was reported in a review of oil spill effects (14) while very high initial respiration rates were observed in some oily waste disposal studies (4, 13). Contrary to results from plot experiments in Alberta (9) fertilizer addition failed to significantly increase CO_2 production by oily sludge-amended Meota loamy sand; in fact within 10 weeks of sludge addition respiration rates in all fertilized and oiled soils were significantly lower than in the respective unfertilized

soils (Table 5).

Population changes of aerobic, heterotrophic bacteria followed a pattern that was similar to the one just described for respiration rates. Again there was a short lag (10 week), especially at the 02 sludge addition level, followed by a rise to maximum numbers at 11 months, when bacterial populations in all waste oil-amended soils were 5- to 8-fold greater than in the respective controls (Table 6). Thereafter, bacterial populations in the oiled soils declined rather gradually until September 1988 (data not shown) when they were no longer significantly different from the controls.

Table 6. Effect of oily waste sludge incorporation and fertilization on microbial populations at 0-10 cm depth in Meota loamy sand

	Sampling date							
	Bacteria ($x10^6$/g O.D. soil)				Fungi ($x\ 10^3$/g O.D. soil)			
Treatment code	Sept. 1986	May 1987	May 1989	Sept. 1989	Sept. 1986	May 1987	May 1989	Sept. 1989
00F0	59	66	67	96	142	239	149	256
00F1	49	103	98	105	147	238	243	304
00F2	47	84	103	75	149	185	300	398
01F0	175	496	117	80	635	818	388	326
01F1	193	508	179	130	190	355	363	416
01F2	121	602	158	99	101	254	337	344
02F0	74	390	136	97	232	521	313	335
02F1	37	561	103	87	82	295	281	287
02F2	89	565	135	98	89	380	272	326

LSD for bacteria at P=0.1 for treatment x date = 92 x 10^6/g.
LSD for fungi at P=0.1 for treatment x date = 218 x 10^3/g.

In contrast to the bacterial response, there were very few significant increases in fungal populations due to EOR sludge incorporation. These occurred only in unfertilized plots at 10 weeks and at 11 months after waste oil addition. For all other treatments and dates there were no population differences from the respective controls (Table 6). Generally similar trends in soil bacterial and fungal population responses to waste oil incorporation were reported from other landtreatment studies (9, 15).

Oily materials are known to exert strong herbicidal effects (14) and the EOR waste sludge being incorporated into Meota loamy sand was no exception. Thus at seven weeks after the sludge application in 1986 there were practically no weeds on any 01 or 02 plots, while a very dense stand of annual weeds (> 100 plants/m^2) had developed on all unoiled control plots. The herbicidal effects of the oily residues were rather persistent because weed infestations in the unsprayed wheat crop grown in 1987 were, on average, 90 and 96% lower on 01 and 02 plots than on the respective control plots (3).

Unfortunately, the phytotoxic effects exerted by the waste oil residues and the remaining brine salts on vegetative growth and grain production by the spring wheat crop were drastically aggravated by the occurrence of severe and prolonged drought stress during the 1987, and even more so, the 1988 growing seasons. The pitifully small grain yield produced in 1988 on the unoiled control plots (Table 7) is proof of the severity of the drought stress. Such extensive and consecutive droughts are considered to be very unusual for northwestern Saskatchewan.

Table 7. Effect of oily waste sludge incorporation and fertilization on yield of spring wheat, cv. Katepwa, during 2 successive years on Meota loamy sand

Treatment code	Grain Yield* 1987 bu/ac	1987 % of control	1988 bu/ac	1988 % of control
00F0	15.8	100	4.3	100
00F1	26.1	100	5.0	100
00F2	22.2	100	5.9	100
01F0	6.9	43	5.3	123
01F1	10.0	39	7.1	143
01F2	11.9	54	10.1	172
02F0	2.5	16	2.5	58
02F1	4.9	19	4.3	86
02F2	5.8	26	6.5	111

LSD (P=0.05) for 1987 yield = 9.5 bu/ac
LSD (P=0.05) for 1988 yield = 4.1 bu/ac

* All values are mean of two 1.0 m^2 samples/plot and 3 replicate plots/treatment cut on September 14, 1987 and on September 6, 1988.

In 1987 grain yields on control and on sludge-treated plots generally increased with N+P+S fertilization and, on average, 01 plots produced almost half, but 02 plots only a fifth as much grain as was harvested from the control plots. The extent of yield reductions due to EOR sludge incorporation 15 months earlier, was very similar to reported reductions (3) in vegetative growth of the spring wheat. Although the quantity of wheat produced on oily waste-treated soil was severely reduced the quality of this grain, in terms of protein content and test weight, was very adequate. In 1988 fertilization again effected significant increases in grain yield but this time only on sludge-treated plots. It seems that fertilizer helps to overcome the phytotoxic effects of oily residues in soil even under drought conditions. This is suggested by the fact that grain yields on fertilized 01 plots were about 60% greater and on fertilized 02 plots about the same as the

respective control yields. Similar beneficial effects of fertilization on plant growth and grain production in oiled soils have been found in other plot experiments (17, 10).

Conclusions

The feasibility of using disposal of EOR-type oily waste sludge for erosion proofing and organic enrichment of cultivated sandy soils in a semi-arid northern environment has been demonstrated. Sludge incorporation greatly improved the soil's structure through large and persistent increases in primary and secondary aggregation. It also effected beneficial increases in soil microbial activities and populations. Under drought stress, cereal grain production was initially reduced by phytotoxicity from the oily residues but later these deleterious effects were largely compensated with fertilization.

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WASTE MINIMIZATION IN E&P OPERATIONS

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Introduction

The purpose of this paper is to examine a practical application of waste minimization to the oil and gas exploration and production (E&P) industry. Waste minimization was formally introduced as a regulatory concept in the 1984 Hazardous and Solid Waste Amendments to the Resource Conservation and Recovery Act (RCRA) of 1976. The concept is broadly defined as volume and or toxicity reduction of a hazardous waste, prior to disposal, and is a method of pollution prevention. Waste minimization is a RCRA requirement for all hazardous waste generators and has typically received little attention in the RCRA-excluded E&P industry. The concepts however have far reaching implications for all waste streams. As stated by Vajda and Stouch, "...the development and implementation of an effective waste minimization program will likely become the single most essential component of the successful corporate environmental program, success being measured in terms of both compliance and costs" (1).

Costs may be broken down into immediate costs resulting from waste management and disposal, and into long-term costs which can result from the liability associated with waste. Such liability results in the ever more expensive remediation of past site contamination and invokes involvement with the Superfund program. The precedent for E&P Superfund participation has been set in the court decision Eagle-Picher v. EPA. By 1990, four exploration and production sites in Louisiana were brought into the Superfund universe. Cleanup costs are high.

The concept of waste minimization can be successfully incorporated in exploration and production operations; however, concepts must be both flexible and site-specific to cover the diverse environment and the extractive nature of oil and gas operations. Extractive operations have little control over product source, or feedstock, and have limited choice for facility location and production processes. Additionally, market conditions govern production activities. Higher petroleum prices increase ultimate petroleum recovery, and in turn, the amount of waste generated at a given production facility. Low petroleum prices have also driven many waste volume reduction measures that are now standard industry practice. The practices, while truly waste minimization, are not normally recognized as such and will not be covered here.

Basic E&P Waste Categories

The 1980 RCRA amendments divided exploration and production wastes into three categories; produced water, drilling fluids, and associated wastes. Figure #1 shows the relative volumes of the three categories, based on a 1985 API E&P waste survey. (2) Produced water is the largest waste category at roughly 21 billion barrels per year, or over 98% of the E&P waste stream volume. The water occurs naturally in subsurface formations and is produced from a wellbore, along with petroleum. Surface facilities separate the undesirable water from the petroleum. The water is then either injected into the producing formation to sweep additional oil towards a producing well, or the water is disposed by injection into a non-producing formation. Less than 9% of the produced water is surface discharged, via a National Pollution Discharge Elimination System (NPDES) permit. Figure #2 gives a breakdown of produced water use and disposal.

Drilling fluids makeup the second largest E&P waste category and are perhaps the most amenable to waste minimization concepts. The fluids can be quite complex and are an essential part of creating a wellbore from which petroleum may be transferred to the earth's surface. Drilling fluids are usually disposed after a wellbore has been completed. If the fluid has an oil-continuous phase or other expensive characteristics, it is normally reused in other drilling operations.

Associated wastes comprise less than one-tenth of a percent, of all E&P wastes. The waste streams are highly diverse in nature and are dependent on both the unique petroleum and reservoir conditions at a specific production facility. In general, the wastes are predominantly a subset of wellbore and petroleum reservoir fluid and solid components. Figure #3 shows a breakdown of the largest associated waste streams.

Time plays a significant role in all three waste categories. Typically, the longer the facility operates, whether a drilling operation or a production facility, the greater the waste stream variance, quantity, and complexity.

Produced Water Waste Minimization

The mechanics of produced water movement in the petroleum reservoir is well introduced by Amyx, Bass, and Whiting, (3) and by Dake (4). Reservoir mechanics, including relative permeability effects, govern produced water production and are responsible for the increase in produced water production over the life of a petroleum reservoir. The irreversibility of the mechanics can most be appreciated by understanding that, when present, produced water primarily dictates the economic life of a petroleum reservoir. Here, waste minimization has its strongest ally - a direct increase in profitability by waste stream reduction. Figure #4 gives a rough approximation for the strong economic incentive to minimize produced water production. The Figure also shows how increased petroleum prices allow a greater level of produced water production, and subsequently an increase in total waste generation.

Produced water minimization is an industry goal - more strongly driven by economics than a regulatory process. The statement strikes hard when proper produced water reuse or disposal becomes too costly as produced water volumes increase. An operator has two choices, one, sell the property to a company

with lower overhead or two, close down the field. When a property has no buyer, the only legal option is to cease operations.

A great deal of research and technology has been implemented to minimize produced water production, beginning with well placement and completion techniques, production and well workover techniques, and ending with application of enhanced recovery techniques. Horizontal drilling is perhaps the most successful technology to date that reduces produced water production. Such technology often maximizes the distance between the wellbore and the reservoir zone of high water saturation (5). Application of the technology is rapidly advancing, strongly driven by profitability - high oil production rates and often proportionately lower produced water volumes offset the often 30%-100% increase in drilling costs. Currently, the technology seems applicable only to reservoirs with specific characteristics.

The waste minimization goal of toxicity reduction can however be widely applied to produced water. Specific chemical additives are used to reduce oil-water emulsions and corrosion caused by produced water. Incentive to reduce toxicity comes from recognition of concerns over both onshore and offshore discharges and from the leaks and spills associated with surface or injection facilities, e.g. chrome contamination. Additives should be carefully evaluated to reduce toxicity and or any RCRA hazardous chemical components. Less toxic or hazardous additives should be used.

While the benefit of such product substitution may seem moot where produced water is safely injected, the substitution decreases the manufacturing of the toxic or hazardous product. Such a decrease has significant benefit in preventing pollution - pollution from product manufacture and pollution from product spillage or mismanagement. Reduction or elimination of EPA's Toxicity Characteristic (TC) compounds in produced water additives is the first goal in waste minimization. Additives of concern are primarily those containing TC metals or aromatic hydrocarbons.

Drilling Fluid Waste Minimization

Drilling fluids offer the greatest E&P waste minimization opportunities. Reduction in waste volume is achievable with both environmental and economic benefits; and, waste toxicity/RCRA-hazards can be reduced or eliminated. However, it is crucial to recognize that waste minimization concepts need to tailored to the level of drilling development activity. An industry "success" ratio of 1 completed well per every 9 exploratory wells drilled typifies the difficulty in understanding subsurface geology, knowledge which plays a significant role in minimizing drilling waste. Consequently, once a field begins commercial development and greater data control is obtained, opportunities arise for improving waste minimization. Conversely, strict implementation of waste minimization on an exploratory well can result in a lack of flexibility to control unanticipated events.

Drilling waste, including drilling fluids and drilled cuttings, comprise about two percent of the E&P waste stream, estimated by API in 1985 at 361 million barrels. Basic waste minimization methods have potential to reduce the stream volume by over 60%. Workover and completion fluids will be discussed in the

drilling fluid waste minimization section because of the technical and operational similarities to drilling fluids.

Well workover and completion fluids were estimated at 5.6 million barrels in the API study and make-up about 48% of the associated waste category. Drilling, workover and completion fluid waste minimization will be discussed in two sections, the first one covering volume reduction; and the second, toxicity reduction.

Drilling Fluid Waste Minimization - Volume Reduction

The role and nature of drilling fluids is well covered by Bourgoyne, Millheim, Chenevert, and Young (6), and in their listed references. The importance of reducing fluid volumes is well recognized for minimizing the environmental impact of a drilling operation. Industry response to meeting the no fluid discharge regulations focused on minimizing drilling fluid discharge through upgrading drilled solids separation equipment. The approach usually involved increased use of equipment and emphasis on its proper installation. Since the equipment was to eliminate fluid discharge to the environment, the term "closed-loop mud system" was established.

As practiced in the past, closed-loop mud systems were not always effective in minimizing fluid discharge to the environment. Fluid ended up in the environment because drilled solids removal equipment was not properly chosen, operated, or capable of removing enough drilled solids created through drilling. Moreover, water used by other wellsite activities and water influxes from nature also contributed to the fluid volumes with which industry had to contend. Lastly, the role of fluid chemistry was seldom recognized in achieving a successful closed-loop mud system. For these reasons, past attempts at minimizing drilling waste were often of dubious success. Opinions on closed-loop mud systems varied widely.

Proper design of closed-loop systems for drilling waste minimization should address three factors:

i) drilling fluid systems should be designed to minimize drill solids degradation,

ii) drilled solids removal equipment should be properly chosen and properly installed; and,

iii) water contacting the drilling operation from nature and other well site activities (e.g. stormwater runoff, rig wash, drill-pipe handling, water lubrication of pumps, etc.) should be diverted and or minimized and reused.

Proper drilling fluid design can minimize the tendency of drilled solids to degrade to smaller particle sizes. Large particle sizes, greater than roughly 10-15 microns, are relatively easy to remove from the drilling fluid, using only mechanical separation equipment. Smaller solids are increasingly difficult to remove. (A buildup of small particle sizes, in the colloidal range, usually results in undesirable drilling fluid properties. This condition normally results in an increase of fluid waste.)

In practice, more inhibitive drilling fluids can be designed over a broad range of complexity - dependent on the drilled formations. Geologic areas of low formation reactivity may only require drilling fluid enhancement by polyacrylamides. Geologic areas with a greater tendency to react with drilling fluid might require inhibition enhancements ranging from addition of more polymers and salts, up through use of oil base drilling fluids. Alternatively, mechanical solids separation can be enhanced through centrifuge/flocculation technology first introduced to E&P operations in 1982 (7). The process separates waterbase drilling fluid into its liquid and solid components.

Performance and cost analysis using the proper combination of drilling fluid inhibition and or flocculation technology, or other solids separation technology, is not amenable to intuition. In 1988, Lal (8) introduced an economics and solids separation performance model which properly analyzed the economics and solids removal performance required to achieve a closed-loop mud system. Several important insights on waste minimization may be drawn from Lal's work:

i) the closed-loop condition of discarding "dry" solids can be meet with less than 100% drilled solids removal efficiency; fluid absorption by cuttings, drilling fluid left behind casing, and site specific fluid density increases allow reduced removal efficiencies, and,

ii) currently, the economics of utilizing a closed-loop system are justified when the combination of drilling fluid, drilling fluid dilution, and fluid disposal costs exceed roughly $6-10 per barrel. (Pit construction and reclamation costs included in disposal costs.)

Figure #5 shows the typical decrease in overall costs associated with minimizing drilling fluid waste, as predicted by the model. Figure #6 shows a case where very low drilling fluid dilution and disposal costs do not economically justify additional solids removal equipment.

One key to achieving the closed-loop condition and a "dry" drilled solids discharge is proper selection of drilled solids removal equipment. (The term "dry" refers to no free liquid on the drilled solids. Figure #7 shows the limiting condition, ranging from about 48%-86% weight percent solids, dependent on the solid's characteristics.) Success at achieving a closed-loop condition can not be met without proper equipment and system design (9, 10).

Optimum drilled solids separation equipment involves use of linear motion shale shakers which maximize fluid-screen throughput capacity and allow running finer mesh screens for a given flowrate. (Shakers used for precleaning or scalping to remove gumbo do not require linear motion.) Shaker performance is discussed in detail by Hoberock and Lal (11).

Hydrocyclone use is discussed in detail by Young (12). Proper combinations of hydrocyclones should be used, with emphasis on the smaller size cones. Decanting centrifuges should be used for both unweighted and weighted drilling fluid solids separation. Installation methods and high g-force centrifuges should be used, as discussed by Thurber (13). Lastly, centrifuge/flocculation systems have been commercialized by several companies. Comparative process

studies have not been conducted - perhaps suggesting service and cost play a major role, as opposed to system design. A performance comparison between various shale shaker capacity, hydrocyclones and centrifuge separation performance is shown by Figures #8, #9 and #10.

The last important aspect of drilling fluid waste minimization covers water use management on a drill site. Lack of proper water management can negate any waste volume reduction obtained from closed-loop mud systems. Table #1 gives the magnitude of some water influxes. Figure #11 shows an inexpensive practical method for capturing and reusing the water. Ideally, attention should be made to reducing or eliminating the water sources by recycling pump lubrication water or using mechanical pump seals, by using high pressure-low volume water hoses, by designing drill sites to divert runoff, and by reducing the areal extent of pits.

Drilling Fluid Waste Minimization - Toxicity Reduction

Data from EPA's report and from API's E&P waste study support EPA's determination (14) that drilling wastes are typically RCRA nonhazardous. Both EPA and API did show data where several reserve pits contained TC hazardous components. Chromium, lead, and pentachlorophenol were the more common components. The components can generally be further reduced or eliminated by product substitution. Table #2, prepared by Kemp (15), lists several examples of generic drilling fluid chemical additives typically available to the E&P industry that contain compounds of potential toxicity concern as defined by RCRA. Toxicity reduction steps may be taken by not using additives with an "E" designation. (Additives with other potential RCRA characteristics such as ignitability, corrosivity, and reactivity are covered under other regulations and normally lose the characteristic when introduced to the drilling fluid.) Polymer additives such as polyacrylamides are suggested as replacement for fluid thinning additives which contain chromium.

The importance of reducing or eliminating RCRA hazardous components is underscored by the concentration of components that occurs as fluid volumes are reduced by closed-loop mud systems and proper water management.

Substantial progress in drilling fluid toxicity reduction has been shown by Bray (16) in Gulf of Mexico operations. EPA Region VI requires bioassay testing of drilling fluids, prior to discharge, and a LC50 of 30,000 ppm or greater. Careful screening and product substitution by Bray has resulted in fluid LC50's that commonly approach 1,000,000 ppm. Figure #12 shows a typical additive screening, while Fig. #13 and Fig. #14 show overall progress in reducing fluid toxicity.

As a final comment on toxicity, care should be taken when evaluating the site-specific use of oil base drilling fluids. Oil base fluids have a greater per unit toxicity than waterbase drilling fluids. However, from a pollution prevention viewpoint, oil base drilling fluids have several important advantages. Formation/fluid interactions are minimized which in turn can reduce wellbore washout on the order of 20% or more. Less washout reduces both the volume of drill cuttings brought to the surface and reduces the volume of drilling fluid required to drill the hole. Reduced formation/fluid interaction maximizes drilled solids separation efficiency because solids do

not readily degrade to particle sizes which are difficult to remove. Drilling fluid dilution requirements are minimized. The high cost of oil base fluids encourages good housekeeping which in turn minimizes spills. Lastly, oil base fluids have good stability, which when coupled with their high cost, greatly encourages recycle and reuse. Peripheral benefits are obtained when oil base fluids contribute to increased drilling performance. In general, the more quickly a well is drilled, the less the environmental impact.

Associated Waste Minimization

Associated wastes are created from oil and gas production processes. Operation economics strive for maximum petroleum production and the minimization of petroleum in any waste stream. Wastes in this category are described in the API Environmental Guidance Document (17), in addition to those E&P wastes that are not included under the RCRA exclusion. API reported that approximately 6 million barrels of associated wastes were created in 1985, not including workover and completion fluids. The wastes tend to be generated infrequently through a wide variety of processes. Chemical constituents in the waste streams tend to mimic those in the petroleum and produced water, though often at higher concentrations.

Cooling tower water is the largest associated waste stream. Waste toxicity reduction can be achieved by substituting chromate corrosion inhibitors and or pentachlorophenol biocides with less hazardous and toxic products. Usually organic phosphonates and or bisulfites can be successfully used for controlling corrosion; and, isothiazolin, carbamates, amines, and gluteraldehydes used as substitute biocides.

Tank and vessel sludges and emulsions can be reduced by increasing the oil recovery from these wastes. Decanting centrifuges - either two or three phase, belt or filter presses, and thermal processes have given documented success in minimizing the amount of waste disposed. Here, oil is recycled to the crude oil pipe line.

The last major associated waste category is spill cleanup, typically involving produced water and petroleum spills. The key is in prevention and awareness. Fewer spills means less contaminated soil and groundwater, which in turn reduces waste disposal, remediation, and future offsite liability costs. Attention to seemingly insignificant drips results in the recovery of substantial fluid volumes, over time. Extra operational awareness reduces spills.

Summary

Waste minimization concepts can be successfully adapted to the E&P industry, though concepts need to recognize the extractive nature of petroleum production operations. In general though, waste minimization makes good business sense because both short and long term waste management costs are reduced. Long term costs arise from cleanup of past onsite and offsite waste disposal, and pose the greatest economic liability to a company.

The E&P industry has high volume, low toxicity waste streams as pointed out by EPA, however, improvements in reducing waste volumes and toxicity may be

reasonably accomplished. Such improvements are necessary to prevent not only E&P pollution, but to minimize the introduction of hazardous or toxic compounds to the environment, either as a result of the manufacturing process or as a result of subsequent product mismanagement.

Product substitution can play a significant role in reducing produced water, drilling fluid, and associated waste stream hazardous components. Closed-loop mud systems and waste water management have potential to economically reduce drilling waste streams by over half, when properly implemented. Limitations to achieving further waste minimization practices are hampered by reservoir mechanics, lack of control over petroleum quality and location, and bound fluid constraints on various solid waste streams.

Support from top management is the first step in initiating a waste minimization program. The second important step involves a complete inventory and characterization of waste streams and chemical additives used in the E&P operation. Subsequent waste minimization steps and processes are given by ENSR (18).

TABLE 1

Common Sources of Water Discharge to Reserve Pits

Source	Average Discharge (bbl/day)
10" Rainfall in 200' x 200' area	6000
Location run-off/near surface aquifers	0-4000
Water Hoses	0-250
Jetting Mud Pits	0-300
Pump Rod Lubrication	0-200
Desanders or Desilters	150-700
Shaker Overs	0-50
Centrifuge Solids Slide	20-100
Water Lubrication of Centrifugal Pump	10-50

TABLE 2

Generic Additive	Potential Toxicity Characteristic
Sulfomethylated Tannin/Dichromate	metals
Melanin polymer derivative	metals
Lignosulfonate/lignite blend	metals
Chrome lignosulfonate	metals
Lignite	metals
Chrome tannin compound	metals
Lignite-sodium dichromate mixture	metals
Sulfomethylated tannin-sodium dichromate	metals
Ferrochrome lignosulfonate	metals
Sodium Dichromate/Chromate	metals
Leonardite	metals

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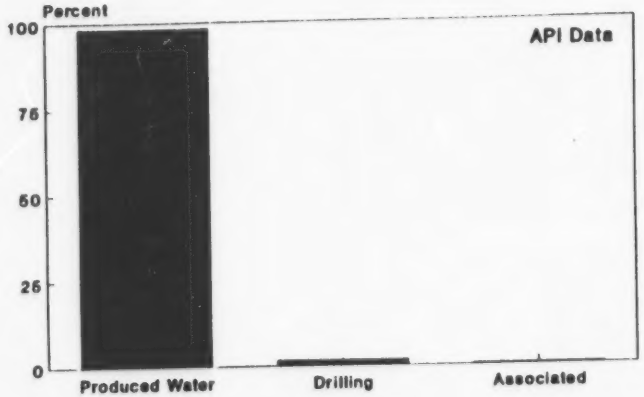

Figure #1

Produced Water Disposal Methods

Figure #2

Associated Wastes
Six Largest Waste Streams

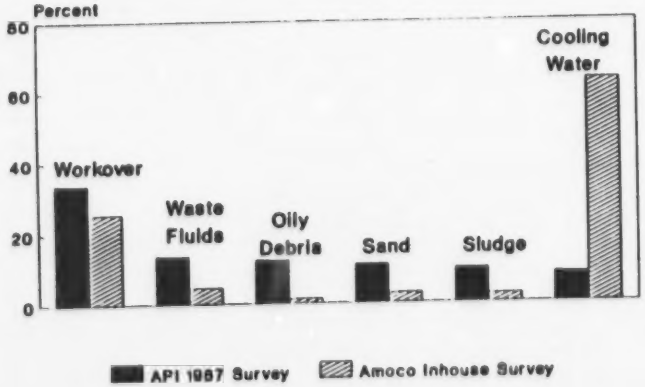

Figure #3

Oil Price vs. Produced Water Production

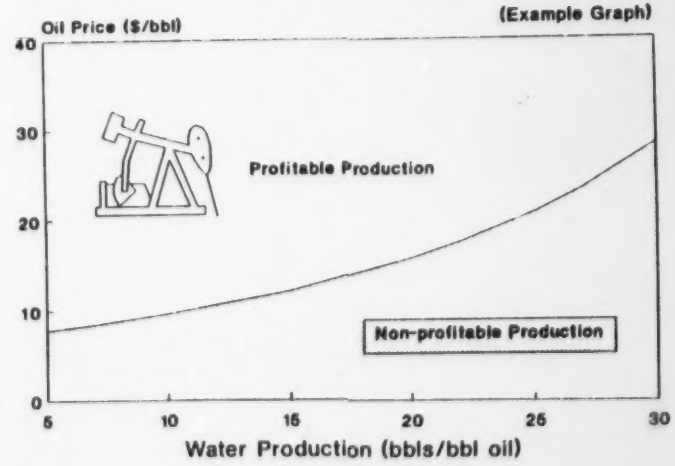

Figure #4

Solids Removal Economic Analysis
Normal Dilution/Disposal Costs

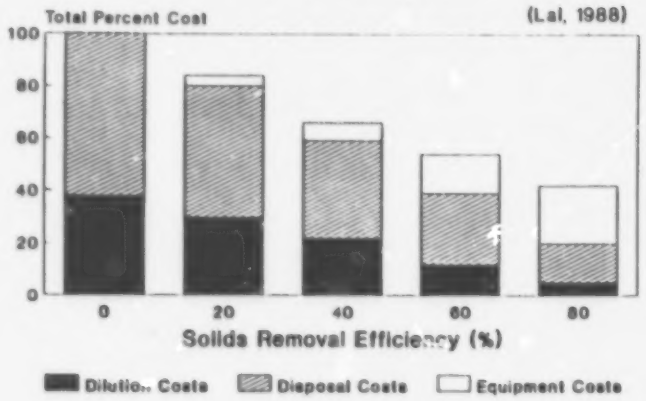

Figure #5

Solids Removal Economic Analysis
Low Dilution/Disposal Costs

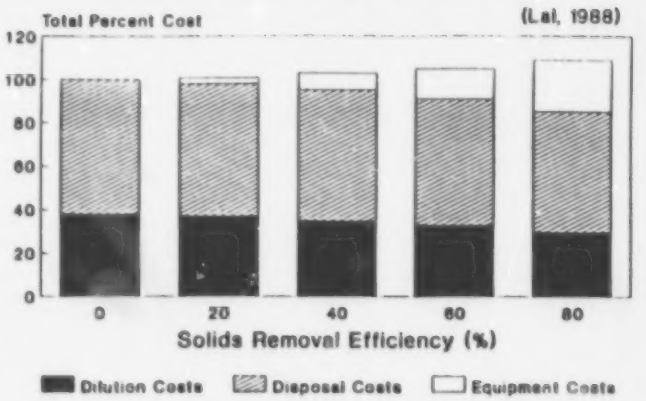

Figure #6

Various Solids Dryness versus G-Force

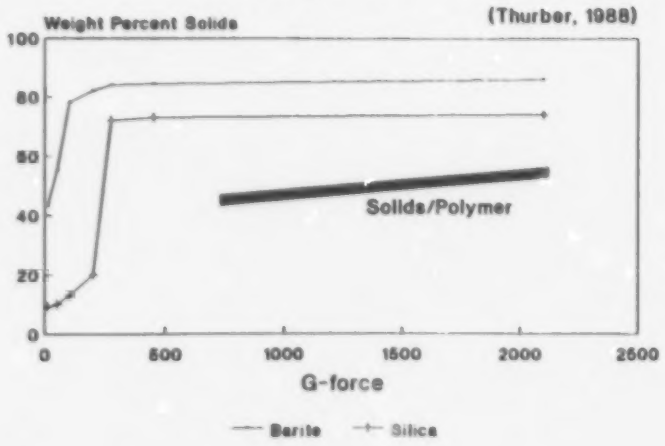

Figure #7

Processing Rate versus Screen Mesh
Water/Polymer Fluid

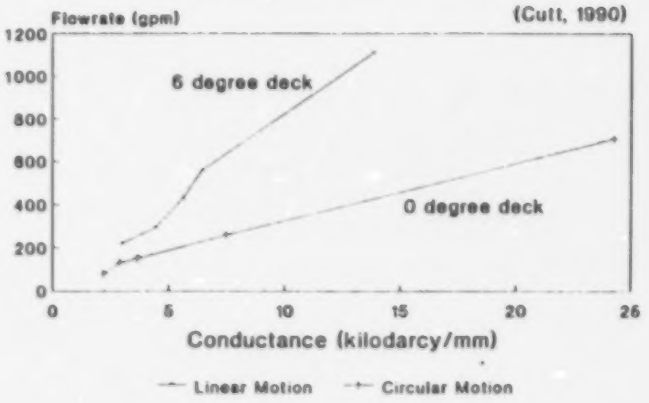

Figure #8

Hydrocyclone Separation Performance

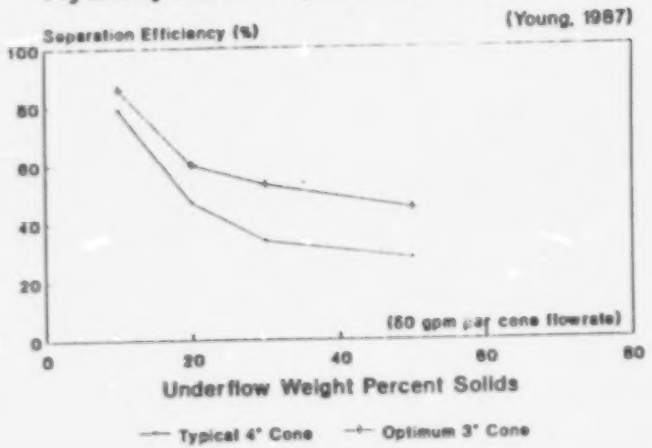

Figure #9

Centrifuge Solids Separation Performance

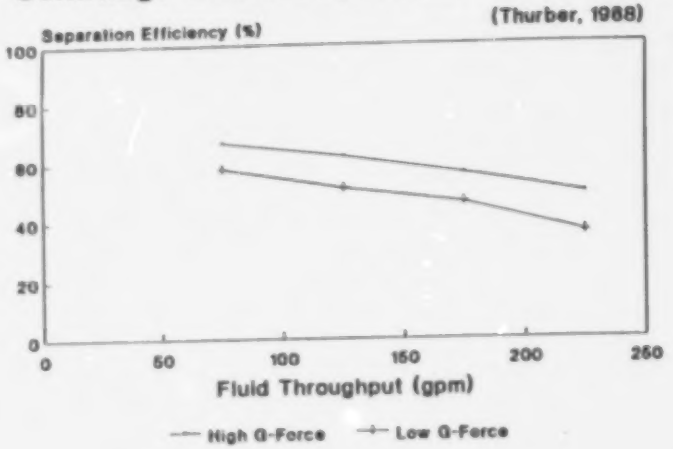

Figure #10

Rig Water Reuse System

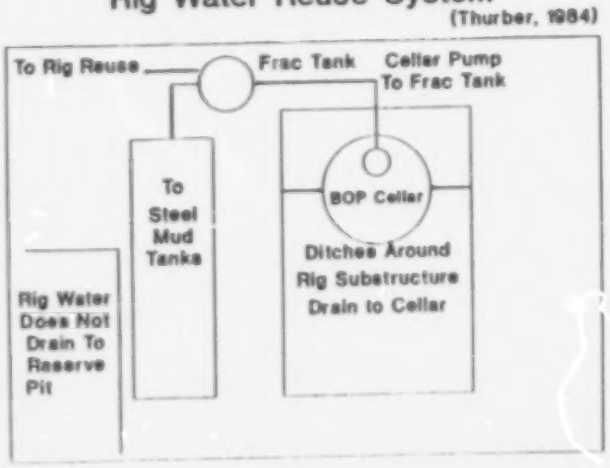

Figure #11

Toxicity Database
Corrosion Inhibitors

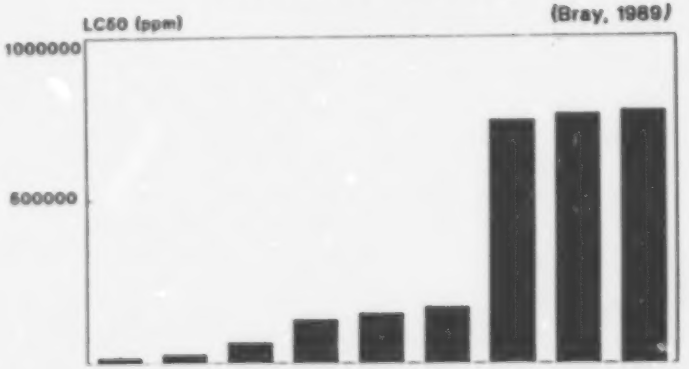

Figure #12

Drilling Fluid Bioassay Test Results
Gulf of Mexico, 1988

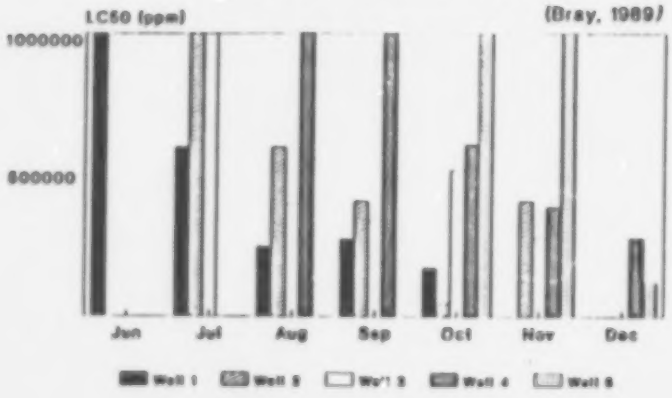

Figure #13

Drilling Fluid Bioassay Test Results
Gulf of Mexico, 1989

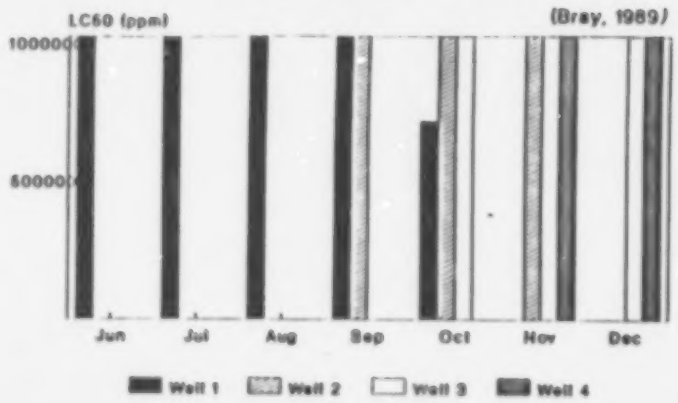

Figure #14

WASTE MANAGEMENT GUIDELINES FOR THE CANADIAN PETROLEUM INDUSTRY

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Abstract

In 1988, the Canadian Petroleum Association (CPA) initiated studies to provide its member companies with management information on 88 types of wastes associated with the production and processing of oil and gas in Canada. The long term intent of these studies was to formulate "Waste Management Guidelines" for use by member companies within their field operations. The studies compiled information from CPA member companies on waste sources, volumes, chemical characterizations, data reliability, present disposal practices and hazard classifications as well as associated studies in Canada and the United States.
For waste types where management and disposal requirements were not clearly identified by Alberta government regulations and/or acceptable treatment/disposal options were not available, a cooperative industry/government workshop was held to establish these parameters.

The final step in the CPA's waste management objectives will be the production in 1990 of the "Waste Management Guidelines and Resource Information Handbook" to promote the environmentally acceptable practices. The handbook's main component is a "Waste Information Guideline" for each of the 88 identified wastes.

Introduction

The Canadian Petroleum Association (CPA) represents medium to large oil and gas exploration, production and pipeline companies operating in Canada. Its members are the industry's major employers, and their combined staff represent a majority of the people who work in the upstream sectors of the industry in the Canadian provinces of Alberta, British Columbia and Saskatchewan. CPA members produce 80 percent of Canada's oil and 70 percent of its natural gas. Virtually all of that production is shipped to market through pipelines operated by CPA member companies. In cooperation with government and other regulatory agencies, the CPA commissions research and helps set operating guidelines for the Canadian petroleum industry.

Some of the early oil field waste management practices which were fairly common to the industry in the 1960's and 70's were the use of both private and public landfills, the flaring of waste hydrocarbons, and the active use of deep well injection for the disposal of a variety of industry produced waste liquids. Ten years ago, the industry found itself moving into a new era of

waste management; and in 1981, the CPA produced "Waste Management Guidelines for Oil Industry Operations". These original guidelines covered 16 waste types.

During the intervening years, government regulations, corporate policies and increased public concern and awareness of waste management forced many companies to examine their policies. In 1988, recognizing the expanding operational and waste management problems facing the petroleum industry, the CPA's Environmental Planning and Management Committee established a Waste Management Sub-Committee. The Sub-Committee's mandate was to develop a CPA position on the practicality and suitability of traditional waste disposal methods with an ultimate objective to produce revised waste management guidelines for field operations. The CPA encourages its members to take full responsibility for the waste that they produce and to ensure that all wastes are properly disposed.

A five phase approach was developed to address the sub-committee's mandate. The first three phases were progressive investigations into the present disposal methods used in the industry. The fourth was a consultative phase involving all major government agencies. The final fifth phase will be the production of the actual guidelines.

Phase I (September 1988)

The objectives of Phase I were to determine:

- what wastes were produced,
- where they were produced,
- how they are disposed, and
- to document any related problems with the current waste management methods.

An industry survey (1) solicited information on the identification of 88 types of waste generated by the industry, and their sources. The most common disposal methods and associated problems were also identified by the respondents. Table 1 illustrates the wastes in List A for which CPA member companies were asked to identify the Current Disposal Method, List B.

The survey was sent to 63 CPA member companies who have active operations (47 producers and 16 pipeline/marketers). The survey response represented 48% of the CPA membership or approximately 65% of Canadian petroleum resource production.
An example of the study results is shown in Table 2 for the waste "Acid". The table indicates:

- the waste source - given as the % occurence that the waste originates from each type of facility;
- the existing disposal methods - the % by volume that the waste is disposed for each method - these results do not necessarily reflect practices recommended by the CPA.

Table 1

Phase I - Waste Inventory

List A		List B
Acid	Iron Sponge	Burn Barrel
Acitivated Carbon	Lab Chemicals - Inorganic	Incinerator
Batteries	Lab Chemicals - Organic	Open Pit Burning
Boiler Blowdown Water	Lubricating Oil - Hydrocarbon	Company Downhole
Catalyst - Non-Sulphur	Lubricating Oil - Synthetic	Contract Downhole
Catalyst - Sulphur	Mole Sieve	Company Landfill
Caustic	PCB - Contaminated Liquids	Other Landfill
Construction & Demolition Material	PCB - Contaminated Solids	Ecology Pit
Containers - Drums Barrels (Used)	Pigging Waste Liquids/Wax	Other Pits
Containers - Pesticide	Process Waste waters	Pond
Contaminated. Debris & Soil - Oil	Produced Sand	Sewage Lagoon/Field
Contam. D & Soil - Mercury	Produced Water	On Site Storage
Contam. D & Soil - Cond./Solvent	Rags -Oily	On Site Recycle
Contam. D & Soil - Produced Water	Scrap Metal	Licensed Reclaimer
Contam. D & Soil - Res. Herbicide	Sludge - Amine System	Licensed Recycler
Contam. D & Soil - Sulphur	Sludge - Classifier / Separator	Returned to Supplier
Cooling Tower Wood	Sludge - Closed Water Drain tank	Other Disp. Company
Crude Oil Sample Bottle Liquids	Sludge - Cooling Tower	Land Farm
Dessicant	Sludge - Crude Oil Slop Tank	On Site Land Treat.
Drip Scrubber Liquids	Sludge - Crude Oil Stock Tank	Road Application
Filter Backwash Liq - DEA	Sludge - DEA Amine System	Irrigation
Filter Backwash Liq - MEA	Sludge - Digestor	Watershed Drainage
Filter Backwash Liq - Water Soft.	Sludge - Filter Backwash Pond	Hazard. Waste Plant
Filter Backwash Liq - Water Treat.	Sludge - Flare Knockout	
Filters - DEA Amine	Sludge - Flare Pit	
Filters - DIPA Amine	Sludge - Fractionator Bottom	
Filters - Glycol	Sludge - Gas Sweetening, Sulfinol	
Filters - Lube Oil (Hydrocarbon)	Sludge - Glycol System, Gas Drying	
Filters - Lube Oil (Synthetic)	Sludge - Inlet Separator	
Filters - Other (raw gas/fuel/air)	Sludge - Lime	
Filters - Process Water	Sludge - MEA Amine System	
Filters - Produced Water	Sludge - Neutralization	
Filters - Raw Water	Sludge - Open Water Drain Tank	
Filters - Sulfinol	Sludge - Process Pond	
Filters - Water Injection	Sludge - Sulphur Block Runoff Pond	
Filters _ MEA Amine	Sludge - Treater Bottom	
Garbage - Domestic Waste	Sludge - Utility Boiler	
H_2S Sensing Tape	Sludge - Water Treatment	
Hydro Test Fluids - Methanol	Treater Hay	
Incinerator / Burn Barrel Ash	Wash Fluids - Solvent	
Insulation / Asbestos	Wash Fluids - Water	
Ion Exchange Resin - Demin.Systems	Well Workover Fluid - Acid Water	
Ion Exchange Resin - H & OH	Well Workover Fluids - HC	
Ion Exchange Resin - Na Cycle	Well Workover Fluids - Prod. Water	

Table 2

Phase I - Waste Inventory. Example of results received for waste "Acid".

WASTE SOURCE

(% Occurence)

30.0%	Gas Processing Plants
7.0%	Gas Compressor Stations
7.0%	NGL Straddle Plants
16.0%	Oil Sands / Heavy Oil Production
29.0%	Conventional Crude Oil Production
11.0%	Pipeline Transmission Facilities

EXISTING DISPOSAL METHODS

A. Total Survey

19 survey responders have this waste.

Reported Disposal Methods

27.8%	Company Deep Well Disposal
19.8%	Contract Deep Well Disposal
13.1%	Other Disposal Company
11.0%	Pond
9.5%	Other Landfill
6.4%	On Site Recycle
6.3%	Returned to Supplier
4.7%	Licensed Reclaimer/Recycler
1.0%	Company Landfill
.2%	Open Pit Burning
.2%	Other Pits

B. Major Companies

7 of the 10 Major Companies have this waste. They represent approximately 39% of resource production.

Reported Disposal Methods

42.9%	Company Deep Well Disposal
26.0%	Contract Deep Well Disposal
12.5%	On Site Recycle
8.1%	Licensed Reclaimer/Recycler
6.3%	Pond
4.1%	Returned to Supplier

Phase II (March 1989)

This phase represented the first industry wide effort to estimate and document the volume of various wastes produced by the upstream Canadian petroleum industry (2). The CPA membership was again canvassed to determine the present inventory and the rate of production for the 88 waste types. In addition, existing analytical data was compiled that included an initial characterization of the wastes. An example of the study results is shown in Table 3 for the waste "Boiler Blowdown Water". Hazardous ratings are based on Alberta government standards.

Table 3

Phase II - Waste Inventory. Example of results received for waste "Boiler Blowdown Water".

WASTE NAME: Boiler Blowdown Water

WASTE SOURCE: This waste includes blowdown from utility boilers, heat recovery boilers and sulphur boilers. It is found predominantly in gas plants and heavy oil stream injection operations. It is estimated that 83 gas plants have this waste..

WASTE VOLUME DATA:

	PRODUCTION ESTIMATE (M^3/YEAR)
Gas Processing:	631,500.0
Crude Oil Production:	0.0
Pipeline Transmission:	0.0
Heavy Oil Production:	5,000.0
Gas Compression:	0.0
Total:	636,500.0

Notes: Volume estimates are based on responses from 4 gas plants and 5 companies representing approximately 18.8% of total resource production.

CHEMICAL CHARACTERISTICS:

Significant Components and Ranges:

Waste composition will be specific to the type of boiler water treatment process.

TDS: 1500 to 3000 mg/l;
PO_4: 5 to 50 mg/l;
pH: 10 to 11;
SO_3: 20 to 60 mg/l.

Classification:

Hazardous:
Non-Hazardous: X

Notes: Chemicals added to the treatment process (corrosion inhibitors) could make this waste hazardous.

ENVIRONMENTAL CONCERNS:

High pH waste, may result in organics leaching from waste water pond sludges.

DISPOSAL GUIDELINES:

Present Disposal Methods:

Evaporation ponds, Deep well disposal

Preferred Future Disposal Methods:

Evaporation ponds, Deep well disposal

Industry Comments:

Large volumes may make disposal a problem for the future.

Ranking:

Low:
Medium: X
High:

Phase III (June 1989)

This phase provided a further investigation of available characterization data and a refinement of volume estimates of the 26 priority wastes identified in Phase II (Table 4).

Table 4
Phase III Priority Wastes

Filters	*Sludges*	*Other*
DEA Amine	Gas Sweetening	Produced Sand
MEA Amine	Sulphur Block Runoff Pond	Hydrocarbon Removal Wastes
DIPA Amine	Process Pond	Process Waste Water
Glycol	Flare Knockout	Wash Fluids, Solvent
Lube Oil (Hydrocarbon)	Flare Pit	Wash Fluids, Water
Lube Oil (Synthetic)	Treater Bottoms	Well Workover Acid Waters
Sulphinol	Tank Bottoms	Well Workover Hydrocarbons
Process Water	Neutralization	
Produced Water		
Raw Water		
Water Injection		

The criteria for priority waste designation included:

- a significant volume of the waste is generated,
- there is a potential for the waste to be hazardous,
- only limited characterization data was available,
- there was a low confidence level in the classification procedure or in the analytical data used for the classification procedure.

Phase III also provided preliminary information regarding potential health and safety hazards associated with the waste materials. Analytical methodology was reviewed and the data's reliability was indicated (3). Sample results are extensive and are therefore not represented in this paper.

During the completion of the first three phases, current disposal practices employed by CPA members were compared to practices used in the United States and Europe. Procedures were generally found to be equivalent. Variations were noted in some areas where legislative/regulatory differences limited or prohibited the use of certain disposal options.

Phase IV (November 1989)

Following the completion of the first three phases, it was necessary for the CPA to more firmly establish, in conjunction with regulatory bodies, specific waste management options. For many waste types, management and disposal requirements are clearly identified by government regulation and facilities are available in the province of Alberta for the treatment and disposal of such wastes. There are, however, other waste types for which government regulations do not provide specified requirements and/or for which acceptable treatment and disposal options are not clearly established.

To address these concerns, a *"round table"* two day workshop was held between CPA members and senior *"decision making"* representatives from the Alberta government departments and three waste management associations. The purpose of the workshop was simply to provide agreement on disposal practices for certain wastes and to identify where further information was required before suitable disposal practices could be recommended. A strong commitment was made to develop effective reuse and recycle strategies, with particular emphasis on methods to reduce and reclaim waste materials.

At the conclusion of the workshop, the government departments agreed to provide more detailed guidelines and procedures based on their regulations for the CPA's guidance (4). In addition, there remained a number of waste types for which more comprehensive waste management procedures were required to ensure the integration of the waste types into a comprehensive waste management plan. Joint government/industry task forces were formed to address the:

- road application of oily wastes,
- incinerator technology for the disposal of oil field wastes,
- disposal of used filters,
- management requirements for process sludges,
- the development of operational criteria for off-site commercial reclaiming and recycling facilities, and
- criteria for deep well waste disposal.

and

The task forces would operate during the development of the Guidelines (Phase V) and provide periodic updates and review during the Guideline's preparation.

Phase V (Completion September 1990)

The final step in the CPA's waste management objectives will be the production of the "Waste Management Guidelines and Resource Information Handbook"which promotes environmentally acceptable waste management practices for the upstream sector of the oil industry.

> *The Guidelines purpose is to assist member companies in the implementation of effective waste management plans within their operations. Essentially, the guidelines are an information resource from which individual companies can develop their own waste management guidelines and corporate strategies.*

The Guidelines address three important concerns of waste management:

- *Environmental* (practicing effective waste reduction, treatment and disposal methods);
- *Handling* (ensuring that adequate employee health and safety precautions are present);
- *Transportation* (ensuring that public safety and transportation regulations are addressed).

Guideline topics include:

- developing a corporate waste management policy;
- implementing effective waste management principles using the 4Rs: Reduction, Reuse, Recycle and Recover;
- methods to classify a waste based on its potential hazardous components;
- a discussion of the merits of the various treatment and disposal methods;
- requirements for effective waste storage and transportation.

The main component of the publication is a "Waste Information Guideline" for each of the 88 identified wastes. These individual guidelines summarize each waste's:

- source and description;
- waste management options based on reduction, reuse, recycling, recovery, pre-treatment requirements and, if required, final disposal methods.
- components and physical/chemical data;
- health, first aid, fire, explosion and reactivity data;
- handling, storage, transportation and environmental considerations;

CPA member companies are urged to follow the format and content of the Guidelines when they are designing their own "Waste Management Guidebook". In many situations, with minor modifications, the CPA Guidelines may suffice as the company guidebook. Some companies may wish to develop more than one guidebook, based on the geographical distribution and technical variations of their operations.

The CPA Guidelines have been designed as an information resource. They are not intended to replace the responsibilities that a waste generator must take to ensure adequate and effective treatment and disposal methods within their regulatory obligations. In particular, the Guidelines do not replace the requirement to perform laboratory analytical procedures. The ultimate goal of the CPA's Waste Management Sub-Committee was to provide the field employee

with correct waste management information. With the production of the Guidebook, the CPA believes that this goal has been accomplished.

Future Efforts

The development of effective waste management principles is continually evolving as certain treatment and disposal methods become uneconomic and/or new and revised policies and regulations are formulated. However, the CPA believes that the cooperative approach which was taken between the oil industry and government to develop the Guidelines, will be of considerable significance when waste management procedures require revision and modification.

Further efforts are required to implement the conclusions of the task forces, to standardize sampling protocols, and to improve the consistency with which waste management procedures are practiced across the industry.

Information on the availability of the Guidelines and any other environmental programs of the CPA can be obtained from the Canadian Petroleum Association, Suite 3800, 150 6th Avenue S.W., Calgary, Alberta, Canada, T2P 3Y7. Phone (403) 269-6721. Fax (403) 261-4622.

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WASTE MANAGEMENT PRACTICES: THE ROLE OF UNIDO

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Before beginning I would like to thank the organizers of this symposium for their hard work, and to emphasize what a pleasure it is for me to be here today on behalf of the United Nations Industrial Development Organization. The subject of the symposium is a very timely one. The rapid acceleration of depletion and degradation of the earth's resources makes sustainable development without doubt one of the greatest, if not the greatest challenge of today. The impact of the petroleum industry and its many derivative industries on the environment is enormous. Both remedial and preventive action is required on many fronts: tackling problems of oil and gas waste management, dealing with hazardous as well as non-hazardous wastes, conducting research into waste characterization, waste disposal techniques, assessment of risks and economic considerations. These and many more. And where the industrialized countries have long experience and practice, most developing countries do not. Indeed, environmental problems often take low priority in the struggle for development. However, the economic aspects of cleaner industrialization are rapidly gaining an audience. More efficient energy utilization in industry, and attention to conservation and proper waste generation, handling and disposal, will lead to considerable savings and an improved economic climate, not to mention the positive potential impacts on long-term health costs and worker safety.

A number of global initiatives have recently been undertaken to identify and enhance awareness of the urgent environmental problems facing humankind. These efforts have been directed towards the alleviation of globally recognized major environmental hazards which know no national boundaries, such as depletion of the ozone layer and global warming, acid rain, hazardous waste and the pollution of

coastal and inland waters. Even problems such as deforestation, which may be geographically confined to a particular region, can have far-reaching global effects.

In developing national and international strategies and in securing government commitment on major environmental issues, there are a few important factors I would like to bring to your attention. First of all, the greater part of current pollution originates in developed countries. Secondly, those countries bear a major responsibility for combating such pollution. And thirdly, international co-operation between developed and developing countries is essential to securing and transferring the required scientific information and environmentally sound technologies.

As you may know, UNIDO is one of the specialized agencies of the United Nations system. Its objective is to promote the accelerated industrial development of developing countries and it runs technical co-operation programmes in about a hundred developing countries. In 1989, UNIDO delivered some US$134 million in technical co-operation and promoted industrial investments of about US$556 million.

Though UNIDO has been actively involved in technical co-operation since 1966 in various projects related to energy and the environment, efforts to develop an organizational philosophy and a programme related to environment started only recently. In May of this year, UNIDO's Industrial Development Board approved a document which contained the elements of a comprehensive programme on environment. The programme is comprised of four subprogrammes, of which the last two are particularly relevant to the issues under discussion during this week's symposium. They are: the promotion of clean, low- or non-waste, recycling or re-use technologies; and provision of technical assistance in pollution abatement through rehabilitation and/or upgrading of existing polluting industries. These activities comprise the heart of UNIDO's work.

A programme for sustainable industrial development should place as much emphasis on the prevention of industrial pollution as on the alleviation of its effects. The adoption of environmentally sound technological processes may ultimately prove their economic value as a result of more efficient use of raw materials and resources. Results are to be achieved through creation of expanded data and information banks within UNIDO and in appropriate institutions in developing countries; description of

technologies; sources of supply; and costs and economic performance, as well as assessment of environmental impact when compared with other technological options. Other outputs will be an expanded roster of experts and data base on institutional facilities, advisory services, pre-investment studies and assessment of clean technologies within the industrial structure and environment of developing countries.

As in the case of energy, greater benefit can sometimes be derived from improvements in efficiency than from investment in pollution control. UNIDO supports adoption of clean, low-waste and energy efficient recycling or re-use technologies and methods in the industrialization of the developing countries. It also assists in the environmental upgrading and rehabilitation of existing industries, especially those contributing most to industrial pollution. We not only promote applied research on, and development of, clean technologies, but we also undertake on-site demonstrations and assessments of the same. All this is backed up by our ever-extending data bases and the preparation of guidelines that will facilitate the incorporation of environmental considerations in the development, appraisal, implementation and evaluation of industrial development projects.

Addressing issues of environment calls for the formulation of policy and regulations that combine industry-specific considerations with broader national, social and economic concerns. It is in this context that UNIDO sees a role for itself. It can contribute to promoting the sustainability of industrial growth, by striking a proper balance between short-term profitability and the need for durable resource and environmental conservation. Within the context of UNIDO's primary mandate to support the industrialization of developing countries, we also endeavour to mobilize additional financial and human resources so as to help developing countries identify, analyze, monitor, manage or prevent industrial environmental problems in accordance with national development plans, priorities and objectives. Since the environment is a global resource, environmental protection lends itself to international co-operation in the transfer of knowledge, science and technology. As the co-ordinating agency for industrial development in the United Nations system, UNIDO is the natural focal point for co-operation in industry-related environmental matters. At the same time, close ties are maintained with UNEP, the United Nations Environment Programme.

Among the resources required for industrial development, energy plays a central role. This is demonstrated by the close structural inter-relationship between energy technological processes and production systems in all industrialized countries. There is an ever increasing recognition that energy economy and efficiency are essential for further industrial development. However, a comparison of the present status of energy management in industrial processes discloses substantial differences between the developed and developing countries of the world.

During the last ten years the energy content of the GNP in most industrialized countries decreased by around 20 percent. Industrial energy efficiency in most developing countries, however, continued to be much lower than in industrialized countries and energy management efforts are still at an early stage. Savings ranging from zero to ten percent and upwards may be achieved by the turn of the century. This would be achieved by the important, on-going restructuring of the overall industrial framework towards fewer energy-intensive and more energy-efficient industries to reduce energy needs in their industrial sectors.

Many developing countries have industrial plants that are often based on out-of-date technologies and economic parameters, so that energy intensity is higher in these industries - 20 to 50 percent higher in terms of energy per unit of output - than in developed countries. Many developing countries depend on imported fuel, mostly oil, which in spite of recent decrease in prices, still continues to be a burden on the state budget and balance of payments. Where energy prices are subsidized, it is difficult to generate internally the financial resources needed for energy conservation investments. Focussed research and development programmes, development of technical skills and improved technology transfer are needed to implement and disseminate new ways and means of achieving energy conservation. A firm institutional base is required to conduct promotional campaigns to provide technical assistance and different advisory services.

One of the most interesting recycling activities in the oil industry is the rerefining of used lubricating oils from engines, gears and hydraulic systems of all kinds of vehicles and industrial machinery. Rerefining of waste oil may include distillation, hydrotreating, and/or treatments employing acid, caustic, solvents, clay and/or other chemicals. The value of a waste oil after treatment can be as either a high Btu content clean burning fuel, or a lube

base stock equal to a highly refined virgin oil. Rerefining of these waste oils means considerable savings of resources and energy, as well as an alternative to the present polluting methods of waste oil disposal. Current practices include indiscriminate disposal into the environment by dumping into landfills, pouring into sewers or domestic drainage systems or applying it to roads to reduce dust problems. The oil leaches into soil and water supplies, releasing hazardous metals into the environment. In other cases, waste oil is burned as fuel with little or no prior treatment, which results in the deterioration of boilers and release of pollution into the atmosphere, since such oils contain heavy metals, chlorines, flourines and other contaminants.

The following figures on commercial consumption of liquid fuels should give you an indication of what's at stake in developing countries. In 1986, according to the 1988 Energy Statistics Yearbook, Brazil's commercial consumption was 45 million metric tons of liquid fuel, while Indonesia's was 24 million and Zimbabwe's 655,000 metric tons. Many developing countries rely heavily on importation of these fuels. Obviously, in addition to the environmental benefits cited above of recycling the waste oil generated are the significant foreign exchange savings possible and the reduction of dependency on foreign imports.

UNIDO has been very active in promoting the recycling of waste lubricating oil. Back in 1985 a working paper was prepared which outlined the rationale and detailed the processes by which waste lubricating oil could be collected, rerefined, blended and reused. Since that time, of course, processes have continually been upgraded. Instead of the acid and clay treatment, for instance, which itself produced considerable quantities of contaminants, various methods such as hydrofinishing ensure a high quality product. Although there are some 60 waste oil rerefining plants in operation in the industrialized countries, rerefining operations have not really had a breakthrough in developing countries in spite of the urgent economic and environmental reasons. Lubricating oils show the highest value-added of all petroleum products due to the sophisticated technology used for their production. Only a few developing countries are currently in possession of lubricating oil production facilities and must rely therefore on imports. This makes the economic benefits of reclaiming waste oil even more attractive. But aside from the hard currency savings and conservation of non-renewable natural resources, the environmental damage of waste oil to soil, ground water and

air in many cities of the third world, as well as the subsequent effects on health, have become unacceptable.

UNIDO started to respond to requests for the establishment of rerefining facilities in developing countries in the mid 1970s. It has already carried out a number of technical assistance projects in waste oil recycling, for instance in Togo, The Seychelles and Burkina Faso. Most recently, a pre-feasibility study carried out at the request of the Government of Thailand showed very positively the benefits of locating a waste oil rerefinery in the Greater Bangkok area. A next phase is under preparation. It will include development of the process scheme and design basis, evaluation of processes, study tours to operating plants employing the processes proposed, and the negotiation of licensing agreements. Upon completion of this phase, it is expected that a waste oil rerefinery costing upwards of US$12 million will be constructed. It will produce base oil, which the major oil companies operating in Thailand have agreed, subject to the final price and quality, to purchase for blending and sale in the domestic Thai market.

Another major activity in the area of waste oil recycling has a more global aim. Under this project, approved earlier this year, regional workshops will be held in each of Africa, Asia and Latin America. Prior to each workshop, a detailed evaluation in the form of a case study will be prepared by UNIDO experts for four countries in each region. This will entail ascertaining the primary users of lubricating oil and estimating the total quality and quantity of oil consumption by industrial, government and commercial users, from which can be extrapolated the different collectible rates of waste oil and identification of the types of impurities expected to be found which would necessitate specialized rerefining methods. The present methods of handling, storing, disposing and recycling of waste lubricating oil will also be examined. Present methods used for waste oil collection, if any, will also be determined and an appropriate system to improve the present one will be designed. Potential locations for rerefineries will also be suggested, as well as the current and potential markets for rerefined products. Full advantage will be taken of the experience gained in industrialized countries in these areas.

These data will be analyzed for each country to determine overall the waste oil rerefining potential and envisaged problems, the technical requirements and financial viability of a rerefining plant, and the national economic

implications, costs and benefits of creating a national capacity to rerefine waste oil. The results will be presented and discussed at the regional workshops. In addition, recommendations concerning the required economic and legislative policy measures will be elaborated. At each workshop, decision makers and technical personnel from the regions will meet together with the UNIDO experts as well as representatives of interested companies, to explore the best ways of transferring this technology to the developing countries.

In sum, UNIDO continues to assist developing countries in selecting the best technologies, not only from an economic but also from an environmental point of view. In this era of diminishing natural resources and mounting environmental crisis, we would do well to engage in activities which conserve and maximize the impact of the inputs while at the same time ensuring that any waste generated is disposed of in an environmentally sound and sustainable way. We are continuing to promote improvement in the efficiency with which fossil fuels are used, both directly and in the generation of secondary energy. Fossil fuel usage is accepted as being irrevocably associated with atmospheric pollution. However, energy demand in developing countries doubled between 1971 and 1987 and will continue to increase rapidly. UNIDO will continue in its efforts through training, research and technical assistance. Technology and production are essential to development, but their negative effects must be addressed as well if sustainable industrial development, not to mention a healthy planet, are to be achieved.

WASTE MANAGEMENT DECISION MAKING PROCEDURE AT PRUDHOE BAY, ALASKA

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Introduction

This paper is concerned with the application of existing and complex waste management regulations and achieving compliance with those regulations in an oil field. It describes a case study in environmental compliance examining one regulatory compliance technique currently employed in the largest oil field in the United States. This case study describes the use of a flowchart to provide a single and consistent point of focus for providing waste management guidelines and disseminating waste management information throughout the oil field.

Background

Prudhoe Bay is the largest oil field in the United States currently producing approximately 1.5 million barrels of oil per day. The field is divided into two working areas and is operated by two companies, BP Exploration Alaska operates the Western Operating Area (WOA) and ARCO Alaska Inc. (AAI) operates the Eastern Operating Area (EOA). This paper describes a waste management tool currently used by AAI in the EOA.

The EOA encompasses an area in excess of 175 square miles. Located within the boundaries of the EOA are a large variety of industrial facilities which include; four oil production facilities, central gas facility, central gas compressor plant, sea water treatment plant, sea water injection plant, waste water treatment plant, crude oil topping unit, 24 drill sites, maintenance facilities, and work force support and living quarters. The size of the work force in the field regularly ranges between 1,500 and 2,000 individuals composed

of AAI personnel, service company personnel, and construction contractors. With shift schedules and 24 hour staffing in all facilities the effective work force size can approach 5,000. This combination of facilities and personnel represents a complex industrial city with a significant potential for waste generation. This industrial city is situated in an arctic wetlands which provides summer habitat to numerous wildlife species. Additionally, the field is isolated from conventional waste management facilities by hundreds to thousands of miles.

Compliance Challenge

The industrial output of Prudhoe Bay along with its associated and varied wastes places these activities under the jurisdiction of many federal and state regulatory programs. The most significant from a waste management perspective are the Resource Conservation and Recovery Act (RCRA), Safe Drinking Water Act-Underground injection Control (UIC), and the Clean Water Act-National Pollutant Discharge Elimination System (NPDES). There are over 8,500 pages of coded federal environmental regulations in CFR 40. These are supported by the daily publication of the Federal Register and other numerous guidance documents. Within RCRA alone there are 17 steps required in the determination of a hazardous waste. Additionally, state and local regulations and permits set many site specific requirements. The challenge lies in how do you simplify complex and overlapping regulatory requirements encompassed by these acts and permits and disseminate them to a large, diverse and often transitory work force. Large segments of the work force may be unfamiliar with facilities in Prudhoe Bay and general waste management options in the State of Alaska.

Compliance Tool

To address the compliance challenge a simplification of complex regulations, and a central focal point was deemed necessary. A "Prudhoe Bay Specific" flowchart was developed to synthesize and coalesce the waste management regulatory requirements and viable recycle, reuse and disposal options. The Prudhoe Bay specific aspect of this flowchart is significant. Presently there already exists many decision matrices and flowcharts for regulatory interpretations. Several of these are contained within the regulations themselves while others are produced commercially. Generic aids are to complex and not activity/site specific. These generic aids assume a certain level of familiarity with regulatory rationale and jargon that frequently does not exist on a widespread basis within the oil field. The

Prudhoe Bay specific flowchart simplifies and translates regulatory framework into field specific activities/sites that the work force is more familiar with.

The Waste Management Options Flowchart currently in use is shown in Fig. 1. The flowchart is composed of four sections; definitions, decision process, management options and examples. The chart provides a framework that assists the user to properly identify their material and to select appropriate reuse, recycle or waste disposal options. Each section was designed to be read from left to right. A discussion of the four sections follows.

Definitions - Federal and State solid waste regulations are definition dependent. Regulatory definitions are presented along the top of the flowchart. The correct management of certain wastes is based upon the source of the material and its waste classification. The management option for a material may not always be the same in every case (see case illustrations below). Each material must be evaluated individually to ensure proper handling.

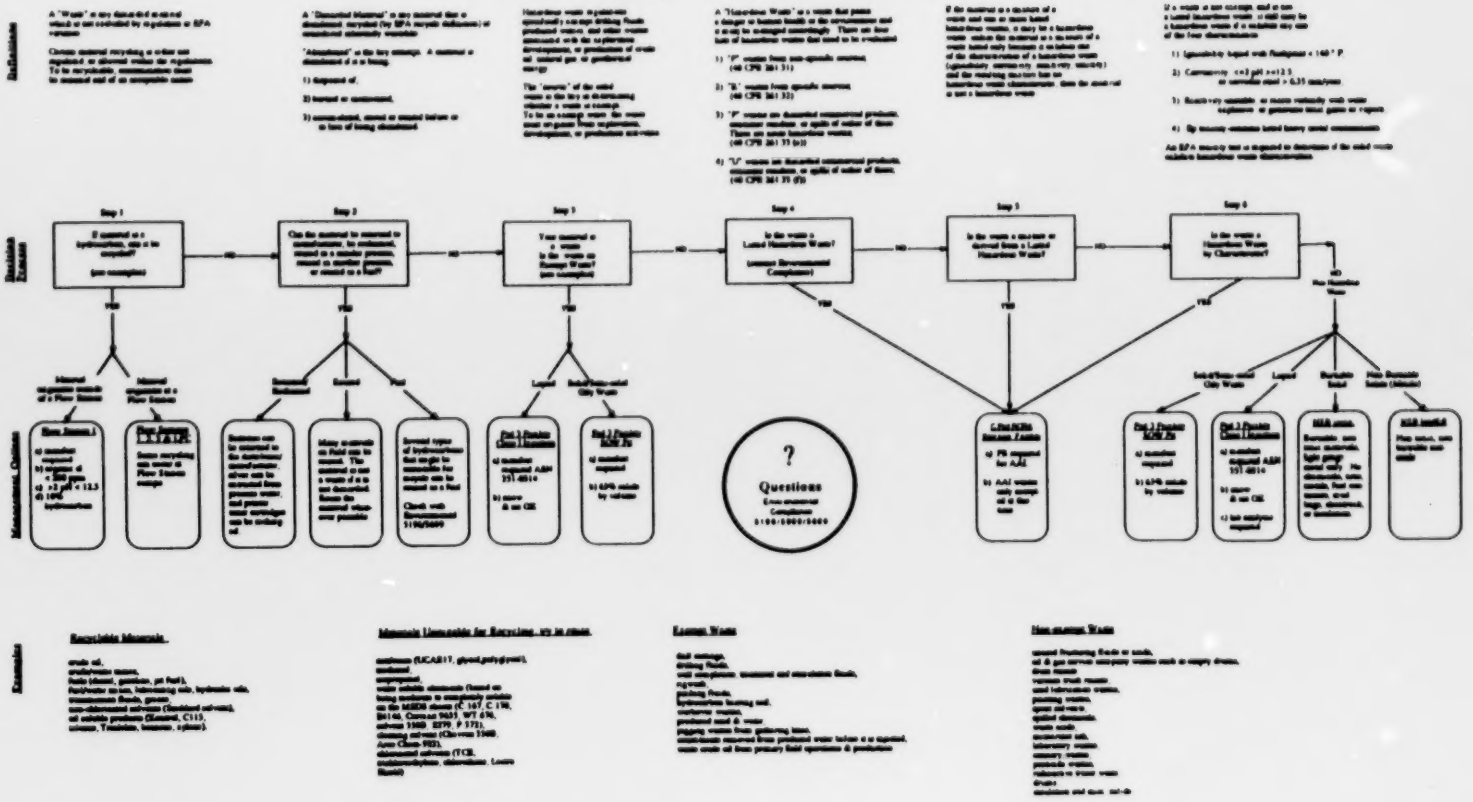
Decision Process - The correct management option is arrived at by answering the questions posed in the decision process. This process is composed of six basic question blocks, labeled Steps 1 through 6. The question for each step is enclosed in a horizontal rectangle. All questions are resolved with a 'YES' or 'NO' response. In all cases, a 'YES' response leads directly to the management solution while a 'NO' response requires additional decision process steps. Located directly above each step you find definitions pertinent to the decision at hand.

Management Options - For each 'YES' response in the decision process you have at least one management option. Approved options are enclosed in vertical, rounded-corner rectangles. Each option has facility operational stipulations that must be met before the material can be received and disposed of at that location. These stipulations are listed for each option.

Examples - Included along the bottom of the flowchart are four lists of materials frequently encountered in the EOA. The first two lists contain materials that are suitable and unsuitable for recycling. The remaining lists provide examples of exempt vs. non-exempt wastes.

This flowchart is a suggested format. The actual wastes and management options available in individual oil field applications will vary, but from our experience the flowchart

Figure 1
Waste Management Options Flowchart



is easily modified to accommodate such variations. This tool has been in use for over a year and has been modified on two occasions as regulatory interpretations and waste management facility options have changed. To date we have not encountered a waste that did not fit within the flowchart boundaries, although I am not suggesting that one does not exist!

Examples

Included below are several illustrations for use of the Waste Management Options Flowchart. For most users in the EOA, if they advance beyond Step 3, the are advised to contact Field Environmental Compliance for assistance.

Case #1 Methanol Spill on snow during well work operation at drillsite. Cleaned up material is a mixture of methanol and contaminated snow.

Step 1 NO, material is not a petroleum hydrocarbon and is unsuitable for recycle (see examples list).
Step 2 YES, material can be reused in freeze protect operation. Process stops here as material is not a waste requiring disposal.

Case #2 Methanol Spill on snow/gravel during well work operation at drillsite (methanol has been down hole in well work application). Cleaned up material is a mixture of snow/gravel contaminated with methanol.

Step 1 NO, material not a petroleum hydrocarbon and is unsuitable for recycle.
Step 2 NO, material is contaminated and is unsuitable for further reuse. Material is now defined as a waste.
Step 3 YES, material is an exempt waste (see examples list), if the material is melted it goes to UIC Injection Facility, if material is a solid it is disposed of at the permitted solid oily waste pit.

Case #3 Methanol Spill on snow/gravel at a storage pad, or while in route to a drillsite. Cleaned up material is a mixture of snow/gravel contaminated with methanol.

Step 1 NO, spilled material is not a petroleum hydrocarbon and is unsuitable for recycle.

Step 2 NO, Material is contaminated with sand and gravel and is unsuitable for further reuse. Material is now defined as a waste.

Step 3 NO, material is not an exempt waste because it was not used in exploration, development, or production activities.

Step 4 YES, methanol is a listed hazardous waste and the spill residue is a hazardous waste. The waste must be transported to the RCRA storage facility.

Case #4 Crude Oil spill on snow during well work operation at drillsite. Cleaned up material is a mixture of crude oil and snow.

Step 1 YES, material is a hydrocarbon and is suitable for recycle. Process stops here as material is not a waste requiring disposal.

Case #5 Crude Oil spill on gravel during well work operation at drillsite. Cleaned up material is a mixture of gravel contaminated with crude oil.

Step 1 NO, material is partly a hydrocarbon but is unsuitable for recycle due to contamination.

Step 2 NO, material is contaminated with sand and gravel and is unsuitable for further reuse. Material is now defined as a waste.

Step 3 YES, material is an exempt waste (see examples list), if the material is melted it goes to UIC Injection Facility, if waste is a solid it is disposed of at the permitted solid oily waste pit.

Case #6 Jet fuel Spill on snow while refueling AAI aircraft. Cleaned up material is a mixture of snow contaminated with fuel.

Step 1 YES, material is a hydrocarbon and is suitable for recycle. Process stops here as material is not a waste requiring disposal.

Case #7 Jet fuel Spill on gravel while refueling AAI aircraft. Cleaned up material is a mixture of gravel contaminated with fuel.

Step 1 NO, material contains hydrocarbons but due to solid nature it is unsuitable for recycle.

Step 2 NO, Material is contaminated with sand and gravel and is unsuitable for further reuse and is a waste.

Step 3 NO, waste is not exempt.
Step 4 NO, waste is not a listed hazardous waste.
Step 5 NO, waste is not a mixture of a waste and a listed hazardous waste.
Step 6 YES or NO, will depend upon the waste. If material is liquid then there is a possibility that the material could fail hazardous waste characteristics, if the material is a solid it is unlikely that it would fail characteristics. Contact Field Environmental Compliance.

Transferability and Adaptability

When the Waste Management Options Flowchart was originally designed it was intended for use in Prudhoe Bay. Due to its relatively simple layout it has been shown to be highly transferable to other oil fields. Another major field in Alaska has recently begun use of the flowchart. The only required changes involved modifying the management options for those available at the new field.

Benefits

There are four significant benefits that we have noted since we started using the Waste Management Options Flowchart. These include; smoother environmental compliance, waste minimization, reduction of fugitive wastes, and improved job satisfaction. Brief discussions of these benefits are included below.

The flowchart allows for consistency in dealing with a variety of wastes and is flexible in determining management options. One payoff from disseminating simplified guidelines on waste management procedures, such as that described in this paper, is smoother and less time consuming field wide environmental compliance. We have found that awareness on the part of the work force is a key to assure compliance. The flowchart is a tool to promote awareness. Throughout the EOA flowcharts have been laminated and stored in vehicles, and posted in facility control rooms and maintenance shops. Even if an individual does not understand all of steps in the process, the flowchart helps to make the individual aware that waste management requires systematic methodology and analysis and different materials must be managed differently.

The decision making procedure promotes reuse and recycling. Users of the flowchart are first prompted to consider whether there is a recycle or reuse application for their material. A 'YES' response in Step 1 or 2 results in recycling or

reuse. In most cases these are the preferred management options because they emphasize waste minimization, are cost effective and involve the least amount of support time.

Consistent application of the decision making process also helps eliminate 'fugitive wastes'. We define fugitive wastes as those that have the affinity to collect in back corners of a warehouse in use by several different groups, on seldom visited storage pads or between buildings. When these wastes are 'discovered' very little is known about them and a financially responsible party is hard to identify. These wastes typically require extensive fingerprinting and sampling for identification. Wastes typically become fugitive because generators are not familiar with management options and the materials are left behind for someone 'more knowledgeable' to deal with. We have found that with widespread distribution of the flowchart these types of wastes are less of a problem as the work force is aware that management options exist. In addition, the chart also tells the user who to contact if they need more information or help. By putting the phone numbers or locations of local environmental support personnel on the chart the user has an even greater range of options. If they are unable to determine the correct management option they can get you involved early. We have found that early involvement of compliance personnel can dramatically cut time and costs when determining material management options. With early involvement pertinent information gets recorded, sample analysis performed, and standardized waste analysis plans are instituted.

Over the past year, through an internal audit program, we have had the opportunity to spend candid one on one time with over one hundred members of the work force discussing environmental issues such as waste management. One rewarding message we received from these discussions was that a better level of job satisfaction was apparent from those that had taken the time to familiarize themselves with the Waste Management Options Flowchart. These individuals felt that they worked in less of an information void than they had before and by understanding the waste management strategies used in the EOA they felt better about our activities as an industry. They now have first hand knowledge that wastes are properly managed and there is method to what a times appears to them to be regulatory double talk and counter intuitive. The over all effect was an improved self worth, job satisfaction and pride in the industry.

Methods of Distribution

Currently in the EOA we have adopted four methods of distributing the Waste Management Options Flowchart. These field rollouts include; dedicated sections in facility environmental manuals, supervisor training sessions, facility safety meetings to the general work force, and specially arranged training with groups having greater potential for waste generation. No one method of distribution has proven to be adequate - rather a combination of these methods has achieved the best effect. Several work groups have distributed plastic laminated versions of the flowchart and the flowcharts are kept in service and utility trucks.

Originally we had hoped that wide distribution of the flowchart with directions and examples would achieve the desired results. This proved not to be the case. Although we tried to simplify the chart, it still was new information and for some too complex to be used effectively. This prompted our current multifaceted approach of distributing the flowchart in combination with training sessions targeted for supervisors and groups with a large waste generation potential.

Summary

To streamline waste management decision making procedures and enhance environmental compliance in Prudhoe Bay a field specific waste management options flowchart was designed. After over one year of use the flowchart has proven to be a useful waste management and compliance tool. The flowchart includes regulatory definitions, a decision process, management options, examples and additional help sources for more in depth information. Waste minimization is emphasized as the user is lead through a decision process that first encourages recycle or reuse possibilities. Several benefits have been realized by distributing the flowchart throughout the oil field. These benefits include enhanced compliance, waste minimization, reduction of fugitive wastes, and improved self and industry image. The most effective methods of distributing the flowchart and guidelines have been a combination of including it under its own section in facility environmental manuals and by providing training sessions to supervisors and work groups with a high potential for waste generation. The waste management options flowchart used in the EOA of Prudhoe Bay has been successfully adopted by another large Alaskan oil field with few difficulties and modifications. The tool described in this paper has enhanced our compliance efforts and we would encourage you to try a

similar approach in your own waste management and compliance efforts.

WHO IS QUI TAM? / PRIVATIZING ENVIRONMENTAL ENFORCEMENT

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INTRODUCTION:

The public's strong desire for stricter environmental protection is encountering obstacles to fulfillment which are inherent in the nature of the issues and the institutions now being employed. Traditional donation-funded nonprofit public-interest organizations have been successful in transforming public opinion into legislation, but enforcement has lagged.

Funding of government agencies has not been adequate to provide satisfactory enforcement of environmental statutes. In addition, there is always a significant risk that government regulatory personnel will be "captured" by their regulated professional peers. The accepted pattern of dependence on state agencies, rather than Federal, for primary enforcement operations under many laws increases the vulnerability of the process, if there is no independent enforcement capability in society.

An appropriate method of improving public-interest participation would be the broadening of existing statutory authorization of citizen lawsuits to include monetary rewards beyond the current provisions for recovery of attorneys' fees where violations of legislated environmental standards can be proven. The creation of a cadre of "enforcement entrepreneurs" would offset, though not eliminate, the problem of serious underfunding and understaffing of State and Federal regulatory agencies.

PRIVATIZATION:

"Privatizing" functions which had been the purview of government --selling or giving them to non-governmental enterprises, usually profitmaking-- was touted by the Reagan and Thatcher administrations, and received a particular boost in the President's budget message in February, 1986.

The common belief underlying most "privatization" suggestions is

that government agencies are inherently less efficient users of resources than private enterprise, and that therefore the public as a whole is better served if any service for which there is a market be provided by profitmaking entrepreneurs.

The concept of "privatizing" should be applied to environmental enforcement. Action should be taken to provide not only the opportunity, but also the incentive for private citizens to bring enforcement actions against violators of environmental laws.

THE ENFORCEMENT PROBLEM:

Despite the rise in popularity of "privatization" in other formerly government-only endeavors, the enforcement of laws is still generally regarded as a public function and private law-enforcement entrepreneurship is viewed with skepticism. However, there are exceptions in existing law, and the climate is favorable for greater private-sector involvement in law enforcement.

Current enforcement of environmental regulations suffers from two weaknesses: funding and will.

Recent environmental legislation has generally established minimum Federal standards for pollution prevention. This has been found necessary to prevent "blackmail" of industry-hungry states by companies who threaten to move across state lines to a less-stringent environmental climate. However, these uniform national environmental objectives are typically accompanied by a reliance on state enforcement. State enforcement levels vary widely.

For example, a 1989 survey of state regulation of oil/gas exploration and production wastes found that the budgets of state regulatory agencies responding ranged from a low of $19/well-year up to $4,054/well-year. Agency personnel resources varied from one FTE per 9.3 wells to one per 5,991 wells. While some state-to-state variation is reasonable, a 600-to-1 ratio "could indicate a staff need... in the upper end of this range," as the report dryly concluded. (1)

These data strongly suggest that a more subtle version of the industry shopping feared at the legislative stage can occur at the enforcement level.

National enforcement is inadequate, as well. At the national level, EPA staff levels were cut throughout the Eighties. Water program staff shrank by forty percent and the total EPA Clean Water Act enforcement staff now numbers only 350. (2) (3) These gaps have not been filled by increased budgets or staff at other levels of government.

The EXXON Valdez spill dramatically illustrated the consequences of "capture" and complacency on the part of regulators. As a result, in January, 1990, the Alaska Oil Spill Commission recommended stronger roles for citizen participation in oil shipment regulation. (4)

As enforcement replaces legislation as the most important element in improving environmental quality, a new source of funds, vigilance, and initiative is badly needed. Bringing individual private citizens into the enforcement universe is overdue.

INCENTIVE SYSTEMS FOR CITIZEN ACTION:

American government today employs three distinct systems to provide incentives for citizen action to enforce statutes: informer rewards, citizen suit provisions, and qui tam laws.

Informer rewards: Rewards to informers are now most actively used by the Internal Revenue Service. The Secretary of the Treasury is authorized to pay "such sums as he may deem necessary" for information leading to the recovery of unpaid taxes from violators of the Internal Revenue laws. (5) The Service has a price list for rewards; the schedule is not generous: 10% of the first $75,000 recovered, 5% of the next $25,000, and 1% of any additional.

Though parsimonious, the program is very effective: in Fiscal Year 1989 $1.5 million was paid in rewards for information which led to the recovery of $72 million. This on only 519 claims allowed. The highest recent year for returns from the program was FY1986, when 820 claims allowed cost $1.3 million in rewards and recovered $258 million. (6) IRS cannot be accused of being profligate (93% of claims filed are rejected), and one suspects that a higher payout rate ultimately would be more profitable for the Treasury.

While informer rewards could be used in environmental enforcement, they depend on the prosecutorial resources of government to be effective. EPA and the states are already aware of many violations which they choose not to pursue, for budget or policy reasons. Those issues are part of the problem, and reliance on informer rewards does nothing to address them.

Recently, the Superfund Amendments and Reauthorization Act of 1986 provided for awards of up to $10,000 to informers whose information leads to arrest and conviction for violations of CERCLA subject to criminal penalties. There has been little experience by which to judge this provision's effectiveness. (7)

Citizen Suits: Since the first legislative provision for citizen suits was included at Section 304 of the Clean Air Act in 1970 , many environmental laws have included "citizen suit" provisions which admit individuals or environmental groups to litigate.(8) However, the possibility of filing citizen suits is not an adequate inducement for significant private-party effort in environmental enforcement.

Recent data on the level of citizen suit activity are incomplete; the most comprehensive study was done by the Environmental Law Institute in the mid-Eighties. (9) Over a six-year period ending in April, 1984, ELI found 349 notices of intent to sue which had been issued, and 189 filed cases, under the citizen suit provisions of five major laws. The Clean Water Act, because of information reported under the NPDES system, was host to the majority of suits. After the study period, it is believed that there was a short time of fairly high citizen suit activity, followed by a decline. (10)

The nationwide level of citizen suit activity cannot be described as high, given the scale of the national industrial base. In recent years, the annual total of <u>all</u> environmental actions commenced in Federal district courts, only a fraction of which have been citizen suits, has averaged about 900 (278,420 district court actions were commenced in 1989; 233,529 of these were civil actions). (11) Why has the citizen suit opportunity not been more widely used? The ability to merely recover costs from a successful action against an environmental violator is not sufficient to spur significant "privatization," yet this is the only financial incentive offered under citizen suit provisions.

Any enforcement program requires research and investigation of many incidents, each of which may or may not lead to prosecution. Citizen enforcement is no different. In the most concentrated use of citizen suit provisions to date, the Natural Resources Defense Council reviewed files on over 1,000 permitted discharges in order to eventually file 18 complaints in the early Eighties. (12) In most cases where a complaint is actually filed, plaintiff may or may not prevail. The long delay between making a large outlay for factual research and eventual collection, and the risk that there will be no collection at all, make filing suits where the best possible outcome is break-even an uneconomical proposition. (13)

As a result, it is no surprise that the great majority of citizen suits have been brought by non-profit organizations which are funded by donations and do not depend on the suits for income. (14) The flurry of Clean Water Act suits brought by NRDC and associated non-profit law organizations in the mid-Eighties led

to speculation that the existing citizen suit opportunities were adequate. However, that spate of action has since dwindled.

Citizens' access to the courts was recently reduced by the Supreme Court in Gwaltney of Smithfield v. Chesapeake Bay Foundation. (15) The "boilerplate" citizen suit legislative language, which has been employed with little change since its Clean Air Act origination, requires giving notice of violation to the EPA, the alleged violator, and the State sixty days prior to commencing civil action. The Court held that cessation of a violation during the sixty-day notice period was adequate to prevent suit, and that "the interest of the citizen-plaintiff is primarily forward-looking." (16) (17)

Thus a citizen-enforcer faces the risk that he may invest time and funds to study 50 sites, add the investment to prepare one case against an identified violator, and yet be foreclosed from recovering even these costs --let alone any reward for risk-- by the timely shutdown of the offending facility. This is hardly an incentive system for private environmental enforcement.

It has been argued that a violating company which remedies the violation within the 60-day warning period should be protected from penalty as a matter of equity. While there may have been justice in this at an early time, environmental violations today are often the result of conscious evasion of regulation until caught. Someone who is pulled over for speeding would hardly argue that he was exempt from ticketing because, at the moment the officer was checking his registration, his car had stopped.

Beyond the fairness question, the value of the 60-day notice provision needs to be judged as it affects an entire regulatory system. If judicially maintained, the Gwaltney view will chill citizen enforcement, and further narrow the inadequate citizen suit path.

Citizen suit provisions were intended more to provide citizen oversight to prevent "capture" of regulators, than to significantly supplant government regulation. (18) These provisions have succeeded in bringing a major change in the flavor of enforcement in some areas, most notably Clean Water Act. However, they do not constitute "privatizing" enforcement and to describe them as such is incorrect.

Qui Tam Actions: The abbreviated Latin phrase "qui tam" refers to legal actions brought by private parties, under statutes which establish penalties for the commission of acts, and which provide for sharing of recovered penalties between the private initiator and the government. (19) "[I]n qui tam actions... society makes individuals the representatives of the public for the purpose of

enforcing a policy explicitly formulated by legislation." (20)

Specific statutory authorization is necessary for qui tam actions, and it is rare. The First Congress enacted a number of qui tam statutes, presumably in an effort to enlist citizen action while the Executive powers were undeveloped. Over time, those provisions were largely repealed or supplanted. (21) The most prominent example of a qui tam provision in effect in Federal law today is the False Claims Act. (22) This Civil-War era statute was enacted to reduce fraud by Army procurement contractors. After decades of decline, the False Claims Act was revitalized in 1986 through the enactment of a package of amendments promoted by Senator Charles E. Grassley (R-Iowa).

Senator Grassley, incensed by estimates that fraud against the government was costing the Treasury up to $50 billion per year, argued that "[t]he solution calls for a solid partnership between public law enforcers and private taxpayers." (23) Grassley described the goal of his amendments as being "to complement the Government's resources by encouraging private individuals to become actively involved in the war against fraud." (24) These same goals are appropriate, and necessary, for adequate environmental enforcement.

The 1986 False Claims Act amendments provided for treble damages and specific forfeitures per false claim. Rewards to persons bringing qui tam actions under the Act normally will range between 15 and 25 percent of the total recovered. This is expected to produce a major rise in fraud litigation by both public-interest and for-profit attorneys. (25)

RECOMMENDED ACTIONS:

Congress should adopt a Comprehensive Environmental Enforcement Entrepreneurship Act, which would (i) establish a general right to file qui tam actions to enforce any environmental statute where citizen suit provisions now exist, (ii) eliminate the Gwaltney problem of polluters who evade prosecution by ceasing their discharges during the 60-day window of opportunity after a notice of intent to sue is filed, (iii) ensure that "standing" challenges, in which environmentalists must demonstrate that they have been directly injured before suit can be brought, no longer work to prevent judicial scrutiny of environmental offenses, and (iv) require that all state programs certified under Federal environmental statutes include similar provisions.

In addition, more identifiable and measurable standards need to be incorporated in environmental legislation and regulation. Where it is unfeasible to write quantitative standards into law,

the law should direct that regulations include such provisions. Only with these standards can the specifics of litigable violations be clearly established.

Some issues deserve further consideration. Should steps be taken to ensure that public qui tam enforcers can obtain access to private sites for inspection and to obtain samples for testing? (Recommendation: Yes, with controls to prevent oppressive zeal.) (26) Should some portion of qui tam awards be required to be reinvested in further enforcement or other non-profit environmental work? (Recommendation: No.)

CONCLUSION:

The recent EXXON Valdez oil spill demonstrates the problem of reliance on regulatory agencies alone for continued long-term vigilance. Environmental enforcement by private entrepreneurs may be more effective than reliance on government staff whose closest professional peers are often the regulated industry personnel themselves. At the least, it is an important complement to agency action which deserves to be encouraged through positive economic incentives. By making every citizen a potential enforcement agent, privatization will put new reality into Dr. Johnson's observation that "conscience is that little voice that tells us someone may be watching."

Private environmental enforcement action cannot totally replace public-agency work, nor should it. But as the spotlight in environmental protection shifts from passage of legislation to the enforcement of laws on the books, it is clear that more resources are needed than agency budgets can provide. Privatization of environmental enforcement, through providing qui tam opportunities which apply to environmental statutes, is essential to complement tax-funded agencies and donation-funded nonprofit activities.

Beyond the quantifiable issues of enforcement budgets and personnel which have been discussed herein lie two more philosophical arguments in favor of privatization of environmental enforcement: representation and innovation. Environmental protection is, literally, the safeguarding of the citizenry's lives. While much of that task must perforce be undertaken by delegates, in a democracy realistic paths (not merely the idealistic opening of citizen suits) should be open for citizens directly to represent themselves and their fellows, and to be rewarded for success in so doing. Secondly, the pride of privatization is its stimulus to innovation and the discovery of more efficient methods of realizing objectives; environmental enforcement needs innovation, and some early efforts have demonstrated what improvements even a

little bit of private-sector invention can produce. (27)

In the long run, a flexible array of enforcement methods is needed. There may be a larger role for informer rewards in the future, and there may be a need for a sharing of roles and powers between private and public enforcers which is more complex than citizen suits or qui tam actions permit. But the first step should be to greatly increase the incentives for public enforcement action. Qui tam powers should be applied to environmental statutes generally. Soon.

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